Kentucky Coal Gasification Project

Feasibility Study

Phase II Report

Prepared by URS Corporation
June 30, 2008

TABLE OF CONTENTS

EXECUTIVE SUMMARY 1

1.0 PLANT DESIGN.......... 9
1.1 Plant Design: Coal Gasification to Liquid Fuels, Chemicals,Clean Electric Power 12
1.1.1 Liquid Fuels from Fischer-Tropsch Synthesis.......... 12
1.1.2 Gasoline from Methanol via Gasification 21
1.1.3 Chemicals from Coal Gasification 24
1.1.4 Power Generation from Coal Gasification.......... 26

2.0 SNG PIPELINE 28
2.1 Transportation Interchangeability of SNG and Natural Gas.......... 29
2.2 Location of Pipeline Interconnect 29
2.3 Lateral Design Alternatives 30
2.4 Capital Cost 34
2.5 Cost of Service 34

3.0 ENVIRONMENTAL PERMITTING Air Permitting 35
3.1 Air Permitting 35
3.1.1 General Air Permitting Requirements 35
3.1.2 National Ambient Air Quality Standards (NAAQS) Attainment Status.......... 36
3.1.3 Prevention of Significant Deterioration (PSD)/New Source Review (NSR) 38
3.1.3.1 Best Available Control Technology 39
3.1.3.2 Class I Area Impacts (Modeling) 40
3.1.3.3 Startup and Shutdown Emissions 40
3.1.3.4 CO_2 Vent Emissions.......... 41
3.1.4 Other Potential Air Permitting Issues.......... 41

4.0 PERMITTING ANALYSIS KENTUCKY SITES.......... 42
4.1 Approach 42
4.2 Assumptions 42
4.3 Environmental Permitting and Licensing 43
4.3.1 Hydrogeologic Permitting 43
4.3.1.1 Floodplain Construction Permit.......... 45
4.3.1.2 Floodplain Development Permit.......... 45
4.3.1.3 Section 401 Water Quality Certication (WQC) 46
4.3.1.4 Kentucky Pollutant Discharge Elimination System (KPDES) Permits.......... 47
4.3.1.5 On-Site Sewage Disposal Permit (Septic System) 51
4.3.1.6 Groundwater Protection Plan.......... 52

TABLE OF CONTENTS

4.3.1.7 Water Withdrawal Permit 53
4.3.1.8 Public Water System Construction and Operations Permits 54
4.3.1.9 Spill Prevention, Control, and Countermeasure (SPCC) Plan 55
4.4 Ecological Permitting 56
4.4.1 Section 404 Clean Water Act Permit / Section 10 Rivers and Harbors Act Permit 56
4.4.2 Threatened and Endangered Species Analysis 59
4.5 Cultural Resources Permitting 59
4.5.1 Cultural Resource Survey 59
4.5.2 Section 106 Review 59
4.6 Kentucky Public Service Commission 60
4.6.1 Certificate of Public Convenience and Necessi 60
4.7 Mining Permitting 61
4.7.1 Underground Mining Permit Application 61
4.7.2 Underground Mining License Application 61
4.7.3 Additional Mining Permits 62
4.8 Federal Energy Regulatory Commission 62
4.8.1 Certificate fo Environmental Compatibility and Public Need 62
4.9 Conculsions 63

5.0 CARBON DIOXIDE SEQUESTRATION 64
5.1 Western Kentucky CO_2 EOR 66
5.2 Multiple Reservoir CO_2 EOR Field Design and Operation 85
5.3 Deep Saline Aquifer Sequestration 91
5.4 Pipeline for Sequestration in Other Basins 93

FOOTNOTES 98

LIST OF ACRONYMS & ABBREVIATIONS

ANR	ANR Pipeline Company
ATR	autothermal reformer
BACT	Best Available Control Technology
bbl, bbls	barrel, barrels
bbl/d	barrel per day
bbls/d	barrels per day
BMPs	best management practices
bopd	barrels of oil per day
Btu	British thermal unit
C_1 through C_4	hydrocarbons with 1, 2, 3, or 4 carbon atoms
CFR	Code of Federal Regulations
C_4H_{10}	butane
CH_4	methane
CH_3OCH_3	dimethyl ether
CH_3OH	methanol
CO_2	carbon dioxide
CO	carbon monoxide
COS	carbonyl sulfide
cp	centipoise (a unit for dynamic viscosity)
CTL	coal to liquids
Cu-Zn	copper-zinc
CWA	Clean Water Act
DOE	U.S. Department of Energy
DME	dimethyl ether
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
FLM	Federal Land Managers
FT	Fischer Tropsch
FWKO	free water knockout vessel
GOR	gas-oil-ratio
GPP	Groundwater Protection Plan
GTL	gas to liquids

LIST OF ACRONYMS & ABBREVIATIONS

GW	gigawatts
H_2	hydrogen gas
HAP	hazardous air pollutant
H/C	hydrogen to carbon ratio
H_2O	water
H_2S	hydrogen sulfide
hp	horsepower
HPS	high pressure saturated
HPSH	high pressure super heated
hr	hour
IGCC	integrated gasification combined cycle
IP	Illinois Petroleum
KAR	Kentucky Administrative Regulations
KDEP	Kentucky Department for Environmental Protection
KDNR	Kentucky Department for Natural Resources
KDOW	Kentucky Division of Water
km	kilometer
KDAQ	Kentucky Division for Air Quality
KNREPC	Kentucky Natural Resources and Environmental Protection Cabinet
KPDES	Kentucky Pollutant Discharge Elimination System
KPSC	Kentucky Public Service Commission
KRS	Kentucky Revised Statute
KY	the Commonwealth of Kentucky
LPG	liquefied petroleum gas
MAOP	maximum allowable operating pressure
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
MEDA	methyl diethanolamine
MIT	Massachusetts Institute of Technology
MMBtu	millions of British thermal units
MMBtu/hr	millions of British thermal units per hour
MMcf	million cubic feet
MMcfd	million cubic feet per day

LIST OF ACRONYMS & ABBREVIATIONS

MMSCFD	millions of standard cubic feet per day
MPSH	medium pressure super heated
MOA	Memorandum of Agreements
MTG	methanol to gasoline
NAAQS	National Ambient Air Quality Standards
NA-NSR	Non-Attainment New Source Review
NEPA	National Environmental Policy Act
NESHAP	National Emissions Standard for Hazardous Air Pollutant
NHPA	National Historic Preservation Act
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NO_x	nitrogen oxide
NSPS	New Source Performance Standards
NSR	New Source Review
NTNCWS	non-transient, non-community water systems
O.D.	outer diameter
O & M	operation and maintenance
OPC	Opinion of Probable Costs
Part I Study	the Kentucky Coal Gasification Project Feasibility Study, Part I
Part II Study	the Kentucky Coal Gasification Project Feasibility Study, Part II
PC	pulverized coal
$PM_{2.5}$	particulate matter (subscript denotes particle diameter, as in 2.5 micrometers)
POTW	Publicly Owned Treatment Works
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
psia	pounds per square inch absolute
psig	pound-force per square inch gauge
PTE	potential to emit
PVT	pressure-volume-temperature
ROI	return on investment
Sasol	a South African-based energy and chemicals company
scf/bbl	standard cubic foot per barrel
SHPO	State Historic Preservation Office

LIST OF ACRONYMS & ABBREVIATIONS

SNG	synthetic or substitute natural gas
SO_2	sulfur dioxide
SPCC	Spill Prevention, Control and Countermeasure
SWPPP	stormwater pollution prevention plan
syngas	synthesis gas, a mixture of carbon monoxide and hydrogen gas
TGT	Texas Gas Transmission
TORIS	Kentucky Tertiary Oil Recovery Information System
tpy	tons per year
TRS	total reduced sulfur
UIC	Underground Injection Control
URS	URS Corporation
U.S.	United States
USFWS	United States Fish and Wildlife Service
VOC	volatile organic compound
Wabash	The Wabash IGCC
WET	Whole Effluent Toxicity

EXECUTIVE SUMMARY

The Kentucky Governor's Office of Energy Policy commissioned URS Corporation ("URS") to perform a study of the feasibility of developing a coal gasification project in western Kentucky. Part I of that study was prepared in the last half of 2007 and Part II was prepared in the first half of 2008. The Part I Study investigated the following topics:

- Availability, quantity, quality, mineability and affordability of western Kentucky bituminous coal to support a large scale coal gasification project
- Suitable plant site locations and proximity of transportation options
- Review of commercially available technologies and basic design and cost for a coal to synthetic (or substitute) natural gas (SNG) facility including project economics
- Suitable plant site locations and proximity of transportation options
- Preliminary review of carbon dioxide (CO_2) sequestration options including enhanced oil recovery (EOR)

The following results and conclusions were reached in performing the Part I Study:

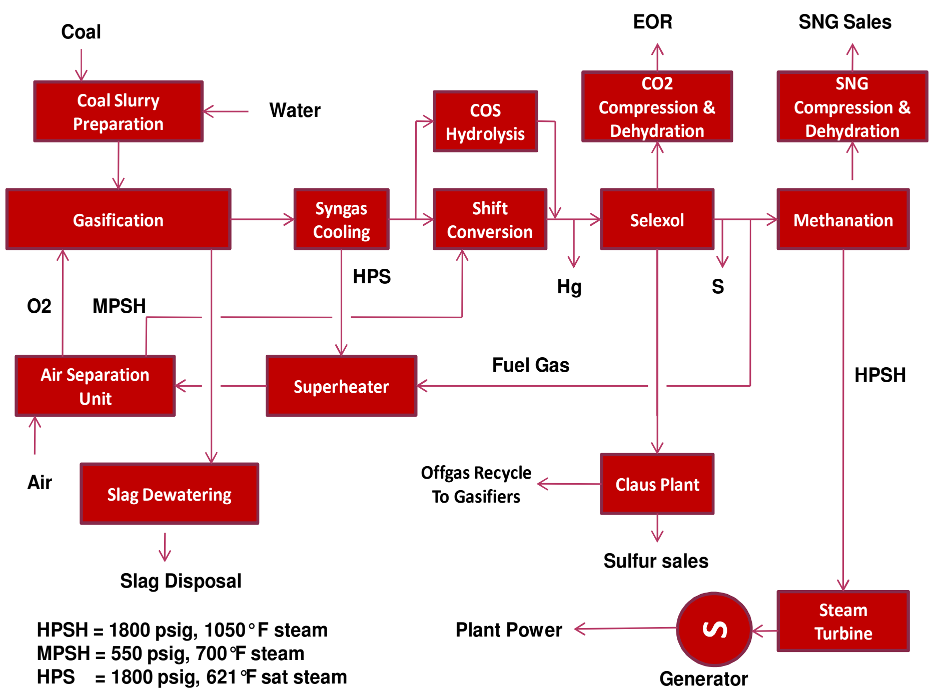
- Evaluation of the western Kentucky bituminous coal as a gasification feedstock was an important task in determining feasibility. Several years worth of core sample data for multiple seams in the area were obtained under a confidentiality agreement from a large mining company. A simplified process design was performed for five different commercially available gasification technologies using this data and all were found capable of producing 175 million cubic feet per day (MMcfd) of SNG from 12,000 tons/day of coal. Sufficient proven reserves in the area can be mined to support multiple plants of this size. As a result **this coal appears to be an excellent gasification feedstock**.
- Field reconnaissance in the area found that potential plant sites up to 2,000 acres adjacent to coal reserves exist. Figure 5-1 in the Part I Study is a map indicating such a site in **Henderson and Union Counties**.
- The Plant Design section of the Part I Study describes and compares the attributes of five different commercially available gasification technologies. A description of all the process and support units that make up a coal to SNG plant is provided. Then a conceptual SNG plant based on two phase slurry fed gasifiers was investigated. Based on this preliminary investigation. It was determined that the projected estimated cost of the gasification facility would be \$2.06 billion. It was further determined that it would cost approximately \$7.80 to \$8.30 per MMBtu to produce the resulting SNG based on \$30 to \$35 per ton coal. This **SNG cost appears marketable** based on natural gas futures prices.

EXECUTIVE SUMMARY

- The acidic gases hydrogen sulfide (H_2S) and carbon dioxide (CO_2) must be removed from the coal derived syngas before conversion to SNG. Conversion of H_2S to marketable sulfur is standard practice in oil and gas processing, but underground sequestration of CO_2 is less widely known even though it has been practiced for enhanced oil recovery (EOR) since at least 1970. The Part I Study investigated geologic sequestration on a broad basis within a 50-mile radius of the proposed gasification plant site including EOR, deep saline aquifers, un-mined coal seams, and organic shale beds. The results were that the Mt. Simon **deep saline aquifer should easily sequester the total CO_2 output of multiple plants** while local EOR could only take up to 4% of one plant's 330 MMcfd output. Although capable of handling small volumes of CO_2, **the EOR option could extend the lives of currently depleted reservoirs** located within a 50-mile radius of the proposed facility for an additional 20 years and result in recovery of 30 million barrels of additional oil making the concept worthy of further study.

Figure 1-3 is a simplified diagram representing the coal to SNG plant described in the Part I Study.

Figure 1-3. SNG From Coal



The Part II Study is in part an expansion on some of the aspects of Kentucky coal gasification development investigated in the Part I Study that were limited by scope and timing. The Part II Study investigated the following topics:

EXECUTIVE SUMMARY

- Description of technologies for gasification of coal to liquid transportation fuels, chemicals and electric power
- SNG pipeline to transport gasification plant product gas to connect with existing pipeline systems of ANR Pipeline (“ANR”) and Texas Gas Transmission (“TGT”)
- Air permitting requirements for a Kentucky coal gasification plant
- All other permitting requirements for a Kentucky coal gasification plant
- Carbon dioxide sequestration

Section 1 – Coal to Liquid Transportation Fuels, Chemicals and Electric Power

In the first section of the Part II Study, the techniques for coal gasification are more fully explained by describing the Fischer Tropsch (FT) coal to liquids process, a coal to methanol (CH_3OH) process and the ExxonMobil methanol to gasoline process. A brief discussion on coal gasification to electric power and coal to methanol to chemicals is also provided.

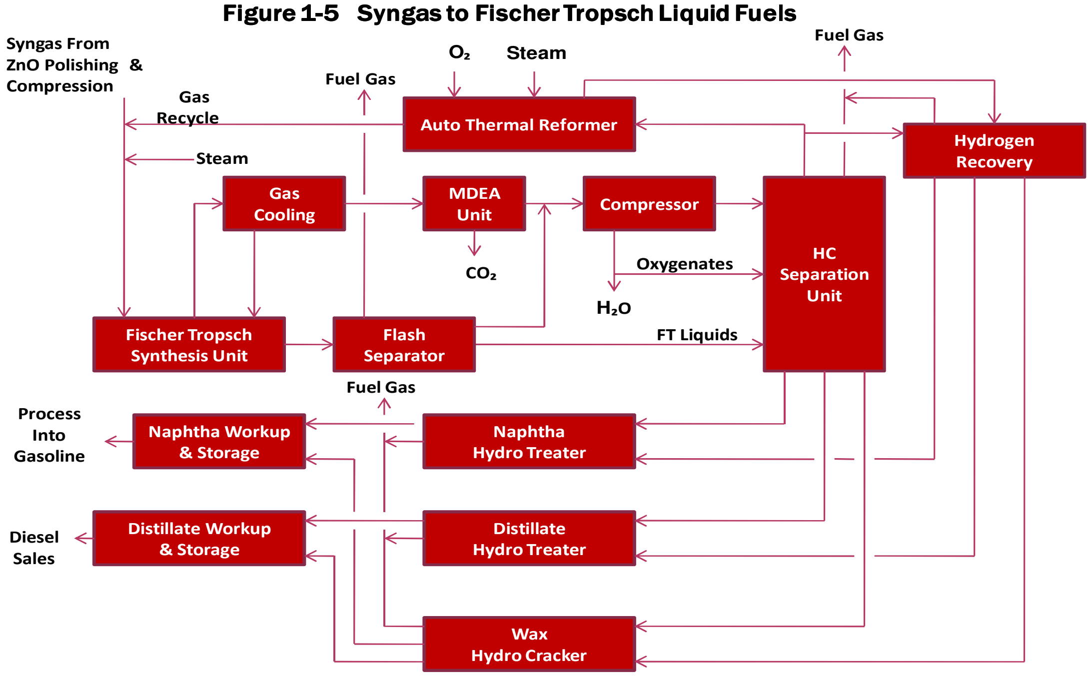
Several of the coal gasification plants being proposed for development in the U.S. today are based on FT technology. Although today’s modern reactors bear little resemblance to the originals developed in 1925, the chemistry is the same. Sasol , a South African-based energy and chemicals company, has gone through several reactor design changes from their original plant in 1955 to present. They are now producing 150,000 barrels per day of transportation fuels and chemicals from coal.

A description of the FT process can be found on the following page. Figure 1-5 below is a simplified diagram representing the synthesis and upgrading sections of a coal to FT liquids plant.

This section of the Part II Study describes how the purified coal derived syngas is converted to FT liquid fuels in the presence of an iron catalyst. Each process step is described and additional process diagrams are included where necessary for a better understanding. A brief description of crude oil refining is provided for comparison. **It is expected that 12,000 tons/day of western Kentucky coal would produce about 25,000 barrels per day of FT liquids that contain approximately 55% marketable diesel and 45% distillate that could be processed into gasoline**. This total plant can be expected to cost approximately twice as much as the SNG plant.

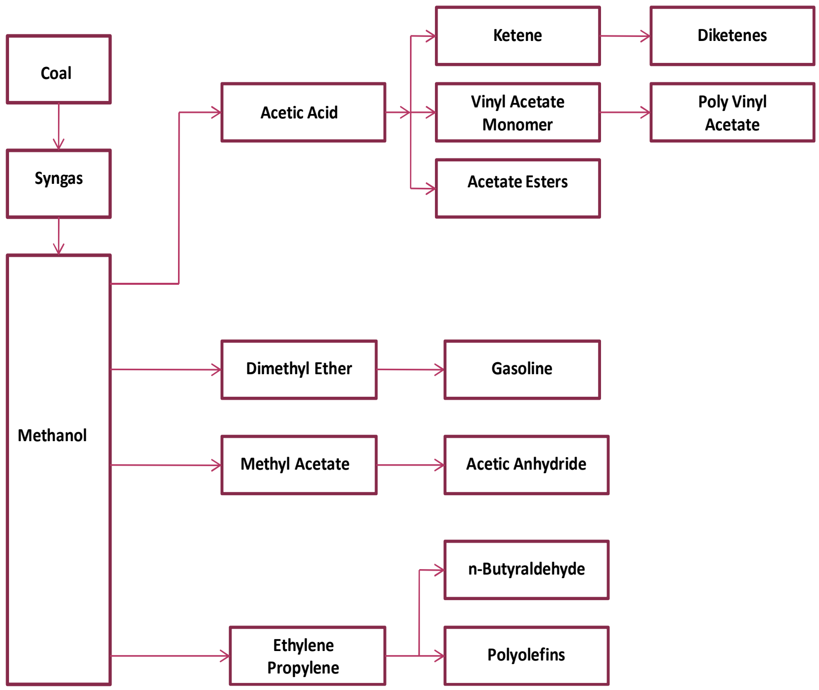
- Methanol is a basic building block of the chemical industry. Figure 1-11 and its accompanying process description in the Part II Study describe a process for converting clean coal derived syngas to methanol over a copper-zinc catalyst. Until recently natural gas reforming has been the main source for methanol production, but gas price increases have forced many plant closings. Eastman Chemical Company currently makes a whole range of chemical products from **coal gasification derived methanol,** as shown in Figure 1-14.

Figure 1-5 Syngas to Fischer Tropsch Liquid Fuels



- **Methanol can also be converted to gasoline** by ExxonMobil's Methanol to Gasoline (MTG) Process. This process dehydrates methanol to dimethyl ether (DME) over an alumina catalyst and then "shape dehydrates" the DME to high octane gasoline over a zeolite catalyst. A plant in Motunui, New Zealand has produced 14,000 barrels per day of 94 octane gasoline from methanol by this process for more than ten years.
- Finally the Wabash Integrated Gasification Combined Cycle (IGCC) Plant in Indiana and the TECO IGCC Plant in Florida have both been **producing electric power by firing gas turbines with coal gasification-derived syngas** for over ten years. Since these were both U.S. Department of Energy (DOE) supported projects, many published reports are available. Figure 1-15 in the Part II Study is a simplified diagram for Integrated Gasification Combined Cycle.

Figure 1-14. Chemicals from Methanol



Source: Eastman Company at Gasification Technologies Workshop, 2008

Section 2 – SNG Pipeline

URS studied several pipeline options to interconnect a Henderson/Union County coal gasification plant to the four existing pipelines in the area. A 30-mile, 20-inch pipeline would have capacity for a single plant output of 175 MMcfd to tie into either ANR or TGT at Slaughter, Kentucky. The capital cost would be approximately $36 million and the transportation cost would be approximately $0.11 per Mcf. Other options are shown in Figure 2-2 in the Part II study including a 30-mile, 24-inch pipeline option which could carry the total output of two plants, thus lowering the transportation cost to approximately $0.06 per Mcf.

Section 3 – Air Permitting Required for a Kentucky Coal Gasification Plant

A URS review of state and federal permitting requirements to build a coal gasification plant shows that an SNG plant in Henderson/Union Counties may be less than an IGCC plant. Henderson and Union Counties are attainment areas for all priority pollutants, as are the majority of Kentucky's counties. This could preclude the more rigorous and time consuming Non-Attainment New Source Review (NA-NSR). However, Vanderburgh and Warrick Counties in Indiana are non-attainment areas for fine particulates ($PM_{2.5}$). A plant designer will have to pay special attention to controlling particulates to avoid delays from rigorous permitting requirements.

The technology is available today to provide steady state operations in which no regulated pollutant would exceed the 100 ton/year threshold that would designate the plant as a "significant" new source. However, unforeseen disruptions in plant operations and restarts involve flaring, and incinerating various gases with limited control options which could add up to levels beyond the 100 ton/year level. This is especially possible in the initial operating years with new, inexperienced operators. If the state and federal regulators determine that this condition makes the source significant, the Prevention of Significant Deterioration (PSD) review would be expanded to include Best Available Control Analysis (BACT) and Class I Area Impacts Modeling.

Section 4 – All Other Permitting Required for a Kentucky Coal Gasification Plant

URS contacted officials of the Commonwealth of Kentucky to determine all the additional permitting requirements for the conceptual coal gasification plant discussed in this study. This section provides a complete listing and description of all the environmental permitting and licensing requirements for a project of this type including the regulating agency, regulation citation and the requirements for obtaining the permits. The facilities covered by this analysis include the:

- Coal Gasification to SNG or IGCC Plant
- Coal Mine
- SNG Pipeline
- Electric Transmission Line
- Carbon Dioxide Pipeline and Underground Storage Reservoirs
- Enhanced Oil Recovery System
- Landfill

Section 5 – Carbon Dioxide Sequestration

This section investigates more fully the primary options of local EOR and deep saline injection for CO_2 sequestration that were discussed in the Part I Study. A new option was developed to transport the CO_2 via a new pipeline to Mississippi where EOR could accommodate all the CO_2 not used by local EOR.

- To investigate the feasibility of local EOR more fully, a hypothetical average reservoir was designed from the available data bases. Core test and other data were applied to this average reservoir to predict the performance of immiscible CO_2 flooding for a 20-year project. The results predicted that a 6.5% recovery is attained at 1.5 pore volumes of CO_2 throughput in the reservoir. **The modeled reservoir recovers an additional 45,500 barrels of oil and provides sequestration for 240 MMcf of CO_2.** These numbers are small, however, but prolonging production of a field near the end of its economic life for another 20 years may make economic sense.

The equipment to efficiently process the production fluid and recycle the CO_2 may be oversized for a single small reservoir. It was assumed that 15 reservoirs could be operated together as a single project, with a central process facility to take advantage of the economy of scale. A conceptual design was made for a 15 reservoir project as shown in Figure 5-8 in the Part II Study. Another conceptual design was made for a possible central process facility as shown in figure 5-9. **The total investment for the central plant, gathering and injection lines and conversion of three wells from water to CO_2 injection in all of the 15 reservoirs was estimated at approximately $8.0 million. The payback is less than seven years based on $100 per barrel oil**. This option would be available to local oil producers regardless of where the majority of the CO_2 will be sequestered.

- As described in the Part I Study, deep saline aquifer storage in the Illinois Basin has the capacity to sequester all of the CO_2 produced in several plants of this size. The Kentucky Geologic Survey is currently designing a test well to determine sequestration potential in western Kentucky. Until that information is available, URS selected sites along the pipeline route to Albion, Illinois that was identified in the Part I Report as having the capacity to accept the plant output. **A conceptual design and cost estimate for a 53-mile, 16-inch pipeline was prepared for this option. The pipeline and injection wells are estimated to cost $90 million and would add about $0.25 to the cost of the SNG**.
- Finally a third sequestration option which exists today is sequestration by EOR in other basins. The URS study team visited Denbury Resources' Tinsley Field in Mississippi to view their EOR operation first hand. Denbury is the largest injector of CO_2 for EOR in the U.S. today with 270 miles of pipelines injecting 600 MMcfd to produce 25,000 net barrels of oil per day. They are planning several new projects in the Gulf Coast region that would accommodate large additional quantities of CO_2. **As a result, URS prepared a conceptual design and cost estimate for a 406-mile pipeline to Mississippi. The cost was estimated at $630 million and would require a $1.00/Mcf transportation** fee. This alternative, while expensive, is attractive because it enables significant increased domestic oil production.

Conclusions and Potential Next Steps

- Feasibility findings suggest that western Kentucky has coal reserves that can provide the source of synthetic (or substitute) natural gas (SNG) at market competitive rates.

EXECUTIVE SUMMARY

There are several options for handling carbon dioxide sequestration including deep saline injection and enhanced oil recovery (EOR) for both local oil reservoirs and other basins such as the Gulf Coast area reservoirs. These can potentially add to the economic appeal of the coal gasification projects.

- Further study may be needed to ensure that all environmental concerns are fully addressed in regards to a coal gasification plant and CO_2 sequestration methods. This includes a more detailed air quality study, impacts to aquifers and water tables, and other potential environmental issues.
- More detailed economic models should be developed to identify the full benefits to the Commonwealth of Kentucky resulting from any coal gasification plants that are considered, and the possible economic tax incentives that may be necessary to encourage energy firms to make the investments for such plants and pipelines.
- To ensure that it's strategic, economic, environmental, and land use objectives are met, the Commonwealth of Kentucky should create development guidelines and performance measures that energy firms should meet in order to be approved for any proposed projects.

1.0 PLANT DESIGN

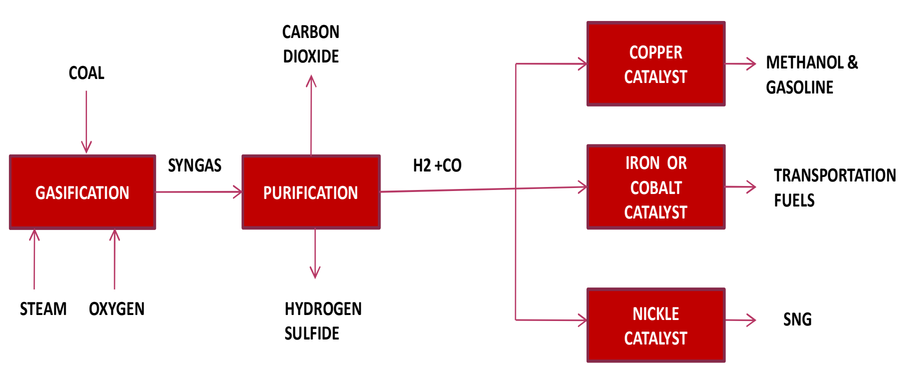
1.0 INTRODUCTION

The Kentucky Governor's Office of Energy Policy has commissioned URS Corporation ("URS") to perform a "Part II" feasibility study in the first half of 2008. The purpose of the Kentucky Coal Gasification Project Feasibility Study, Part II ("the Part II Study") is to more fully describe aspects of potential coal gasification projects in western Kentucky which were beyond the scope of the "Part I" feasibility study. The Kentucky Coal Gasification Project Feasibility Study, Part I ("the Part I Study") described a number of topics that a potential project developer would need to investigate prior to considering the large investment required to develop a coal to synthetic (or substitute) natural gas (SNG) project in western Kentucky. As such topics discussed in the Part I Study included:

- Availability, quantity, quality, mineability, and affordability of western Kentucky bituminous coal to support a large scale coal gasification project
- Suitable plant site locations and proximity of transportation options
- Review of commercially available technologies and basic design and cost for a coal to SNG facility including project economics
- Preliminary review of carbon dioxide (CO_2) capture and sequestration options including enhanced oil recovery (EOR)

Although focused chiefly on the processes which are utilized to turn coal to SNG, the Part I Study included a brief discussion of how coal gasification works and how synthesis gas ("syngas") produced from coal gasification is used in producing clean electric power as well as a wide range of fuel and chemical products that historically have been produced mainly from petroleum feed stocks.

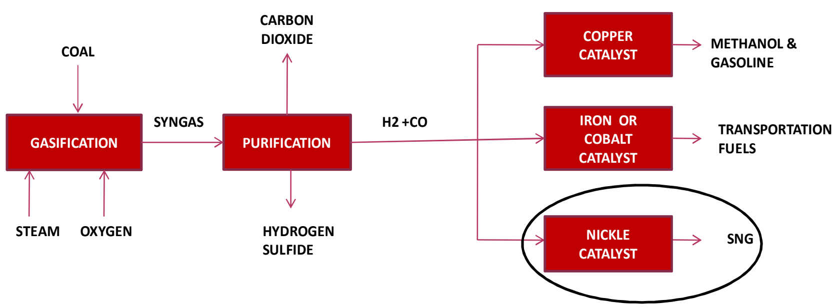
Figure 1-1 Generic Coal Gasification



1.0 PLANT DESIGN

Figure 1-1 illustrates in a very simplified diagram, how purified synthesis gas, also known as syngas, produced by the gasification of coal, can be converted to methanol (CH_3OH), gasoline, diesel, jet fuel, chemicals, and SNG. Syngas is a mixture of carbon monoxide (CO) and hydrogen gas (H_2). The key differences in the processes used to produce the various aforementioned products are in the synthesis reactor designs and catalysts used to convert purified syngas into the desired product. The Part I Study was devoted chiefly to discussing a project designed to convert 12,000 tons per day of Western Kentucky bituminous coal to 175 millions of standard cubic feet per day (MMSCFD) of SNG using a nickel-based methanation catalyst as shown in Figure 1-2.

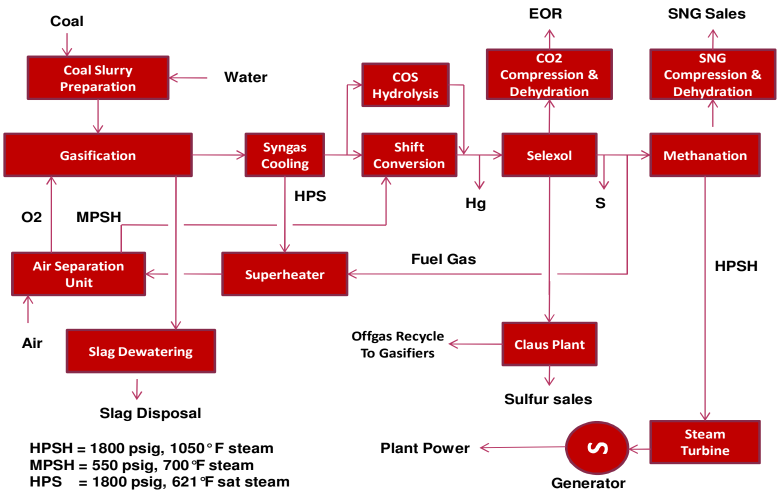
Figure 1-2 Select SNG Option



All the individual process and support units that make up a coal to SNG project were described in considerable detail in Section 3 of the Part I Study. Simplified process flow sketches and written descriptions of each process step were provided for the majority of those units to better understand how those units function. Design parameters that are used to evaluate the different technologies available for each process were also discussed. Because of the detail provided on the coal to SNG option in the Part I Study, the description of those process steps which are common to most gasification plants will not be repeated in this Part II Study. For reference, a simplified flow diagram representing the SNG plant is shown in Figure 1-3. While the Part I Study focused upon the description of the support units and processes utilized to convert coal to SNG, it is important to note that regardless of the desired final product most coal gasification plants use common technologies, processes and support units regardless of what the final desired end product is. As such the focus of this Part II Study will be the utilization of gasification technologies to produce products other than SNG.

1.0 PLANT DESIGN

Figure 1-3. SNG From Coal



The summary of the main findings of the Part I Study includes:

- Adequate mineable coal reserves exist in the Western Kentucky Coal Fields to support several coal gasification plants of this size with an expected 30-year project life.
- Preliminary review of the Study area shows several potential plant sites of sufficient size and apparent quality are available. Detailed studies would have to be conducted of each potential site to be sure they meet all the requirements.
- Western Kentucky bituminous coal will make an excellent feed for gasification. There are at least five (5) commercial gasification technologies that could potentially be employed that have the capacity to convert 12,000 tons per day into 175 MMSCFD of SNG.
- An estimated total project cost of $2.06 billion and an estimated annual operating cost of $228 million results in a gas cost of $7.96 per million British thermal units (MMBtu) for a base case plant design.
- The base case assumes a 30-year project life, 3-year construction, 90% availability for 3 years after startup, 75/25 debt/equity ratio, 8% interest on debt, 15% return on investment (ROI), 3% inflation, 40% tax rate, and $30 per ton coal cost.
- Either a $5 per ton coal cost increase or a 10% cost overrun would add 34 cents per MMBtu to the cost of gas.
- This is an environmentally friendly use of coal resources since high conversion efficiencies are employed and more than 99% of the coal's sulfur is removed and converted to a saleable product and 90% of the carbon dioxide produced in converting the coal to SNG is captured and compressed to 2,200 pound-force per square inch gauge (psig) in preparation for use in EOR or sequestration in deep saline aquifers.

1.0 PLANT DESIGN

- The preliminary review of potential EOR candidate fields in a 50-mile radius of the plant site indicated that only 4% of the plant's 5.8 million tons per year of CO_2 could be used in local oil fields. Thus, longer transportation to more appropriate fields and deep saline sequestration will be studied. The Part II Study will look more closely at both modes including infrastructure and cost requirements for a reference design.

As previously discussed, Part II of the Kentucky Coal Gasification Project Feasibility Study first focuses on the uses of coal gasification for other than SNG production such as production of transportation fuels using Fischer-Tropsch synthesis, production of chemicals starting with methanol synthesis and production of clean electric power by burning clean syngas or hydrogen gas (H_2) in a gas turbine combined cycle operation. The study then returns its focus to the SNG plant design of the Part I Study to cover those facets which could not be covered in sufficient detail within the scope of the Part I Study: These facets are:

- Environmental Permitting Requirements
- Design and cost of pipeline facilities to get the SNG to market
- Design and cost of pipeline facilities to get the CO_2 to EOR or saline sequestration
- Design and cost for an average EOR operation

1.1 PLANT DESIGN: COAL GASIFICATION TO LIQUID FUELS, CHEMICALS AND CLEAN ELECTRIC POWER

1.1.1 Liquid Fuels from Fischer-Tropsch Synthesis

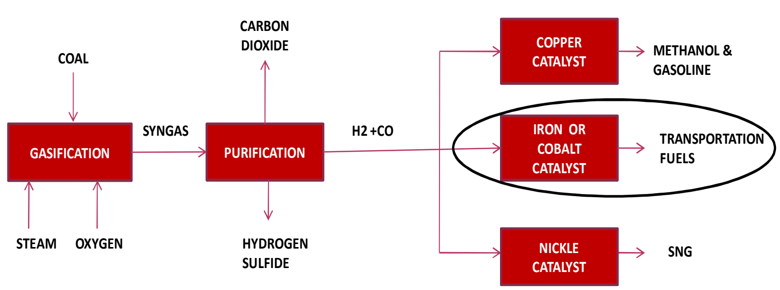
Dr. Franz Fischer and Dr. Hans Tropsch developed a method of indirect liquefaction of coal in 1923 by first gasifying the coal and then reacting the resulting syngas in the presence of an iron catalyst to convert the syngas to a mixture of liquid hydrocarbons. Germany used similar technology during World War II to produce liquid transportation fuels from coal in order to augment their petroleum based supply.

Sasol, a South African-based energy and chemicals company, has been the major proponent of this technology since they started-up SASOL I in Sasolburg, Orange Free State in 1955. The original plant used Lurgi's three meter moving bed gasifiers together with fixed bed tubular Fischer-Tropsch (FT) reactors. Seeking to improve capacity and product mix they added newer Lurgi Mark IV (4m) gasifiers with circulating fluidized bed FT reactors. In 1980 and 1982 Sasol started up SASOL II and SASOL III in Secunda, Transvaal with Lurgi Mark IV gasifiers and circulating fluidized bed FT reactors. Sasol tested newer high capacity fluidized bed FT reactors at Sasolburg in 1989 and then replaced all 16 original reactors at Secunda with 4-11,000 barrel per day (bbl/d) and 4-20,000 bbl/d fluidized bed reactors from 1995 to 1998. Today Sasol produces 150,000 barrels of liquid transportation fuels and chemicals per day from the liquid hydrocarbons derived from coal gasification. The total capital cost for all three facilities was over $6 billion.

In the 1990's Sasol discovered their first large domestic natural gas reserves offshore from Mossel Bay which is between Cape Town and Port Elizabeth of the coast of South Africa. They installed facilities to reform this natural gas into syngas and then to synthesize liquid fuels and chemicals via FT with a proprietary catalyst. Sasol has recently collaborated in a 34,000 bbls/d gas to liquids (GTL) plant in Qatar. This technology presents an interesting option for utilizing stranded natural gas which is a byproduct of oil production.

The processes in the front end of a coal to liquids plant are essentially the same as those required for a coal to SNG plant. Carbonyl sulfide (COS) in the syngas must be converted to hydrogen sulfide (H_2S) in a Hydrolysis or Shift Conversion unit to accommodate the downstream removal of sulfur to very low levels. Hydrolysis of COS must be accomplished but a Shift Conversion Unit may or may not be required depending on where the developer decides to recover hydrogen for hydro treating and hydro cracking the crude FT liquids in the product upgrade area. Hydrolysis occurs in the presence of shift catalyst but little or no shift occurs in the presence of hydrolysis catalyst and the alumina-based hydrolysis catalyst is less expensive. The starting point is to select the iron or cobalt catalyst option as shown in Figure 1-4. These catalysts promote not only the FT reactions but also the shift reaction which results in additional H_2 production in the FT reactor.

Figure 1-4 Select Fischer Tropsch Transportation Fuels option



The gasification of 12,000 tons per day of western Kentucky bituminous coal would be expected to produce sufficient syngas to ultimately produce 25,000 barrels of liquid fuels and chemicals per day when processed in FT slurry bed reactors over iron or cobalt catalyst. Numerous reactions take place that can be represented by the following equations:

$n\,CO + 2n\,H_2 \longrightarrow C_nH_{2n} + n\,H_2O$	Olefins
$n\,CO + 2n{+}1\,H_2 \longrightarrow C_nH_{2n+2} + n\,H_2O$	Paraffins
$CO + H_2O \longrightarrow H_2 + CO_2$	Shift Conversion

1.0 PLANT DESIGN

The FT reactors produce a mixture consisting of a wide range of hydrocarbon products from methane all the way to C_{100+} heavy waxes. Unlike SNG plants where maximum methane is the goal, methane is undesirable in FT plants and has to be separated from the mixture, reformed to syngas and recycled to the reactor. Syngas composition, temperature, pressure, catalyst, and reactor design all can be tailored to alter the product mixture. For example temperatures over 500 degrees Fahrenheit (°F) and iron catalyst will result in more naphtha with smaller but more complex hydrocarbon molecules which are more easily converted to high octane gasoline. This high temperature mixture will also contain more oxygenates such as alcohols, ketones, and aldehydes. Use of cobalt or iron catalyst at lower temperature around 400°F will result in additional longer chain hydrocarbon molecules which can be separated as diesel or hydro cracked to diesel.

It order to better understand the processes required to separate and upgrade the crude FT mixture it may helpful to compare them to the processes a petroleum refinery uses to make similar products from crude oil. Crude oil is also a mixture of a wide range of hydrocarbon molecules. One major difference is that most crude oil still contains sulfur and other contaminants which must be removed from the products by processes such as hydro desulfurization. In gasification-based plants those contaminants will have already been removed from the syngas to very low levels before FT synthesis to avoid poisoning the FT catalyst. As a result the FT fuels will be cleaner and emit fewer pollutants when burned.

A refinery first separates crude oil into several fractions by continuous distillation at high temperature. Each fraction is itself a mixture of hydrocarbons. The major fractions starting with those coming off the top of the column at the lowest temperature and increasingly heavier fractions coming off at higher temperatures at take off points further down the column are the following:

- Methane (CH_4) through butane (C_4H_{10}) gas comes off the top of the column and is typically liquefied as LPG or converted to olefins and used in plastic manufacture.
- Light naphtha having molecules of six or less carbon atoms comes off near the top and after hydro desulfurization is typically processed in steam crackers to produce olefins like ethylene, butadiene, and benzene.
- Heavy or straight run naphtha is rich in naphthenes and aromatics and is typically processed into gasoline blend stock in catalytic reformers. Most gasoline production today requires catalytic reforming to produce more complex molecules and cyclic compounds and may require alkylation to add methyl groups and branching to increase octane rating.
- Gasoline is a mixture of branched and cyclic aliphatic compounds which may require blending with the products of catalytic reforming and alkylation to achieve a specific octane rating. Straight run gasoline may have octane ratings from 20 to 75 depending on

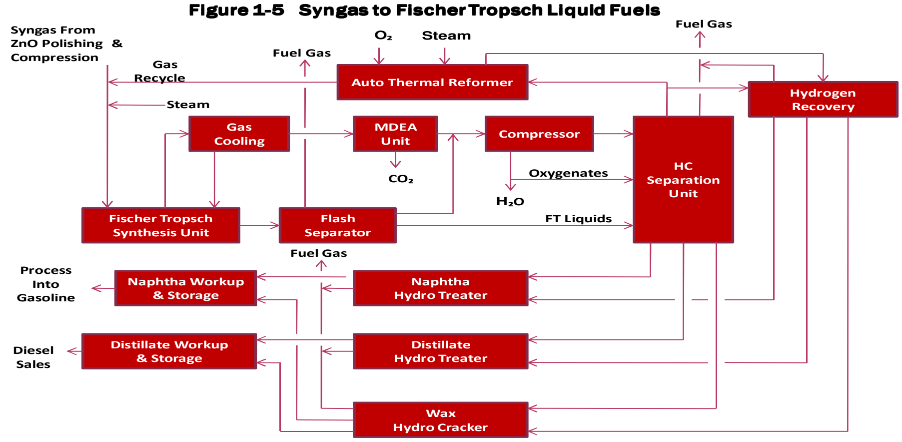
the crude it is distilled from. Isooctane or 2,2,4-trimethylpentane is considered as having an octane rating of 100.

- Kerosene is a mixture of paraffins and aromatics containing molecules with up to 18 carbon atoms. Jet fuels are produced from this fraction.
- Diesel is a mixture of aliphatic hydrocarbons containing 12 or more carbon atoms. It is used as transportation fuel or fuel oil. The ignition quality of diesel fuel in engines is represented by the cetane number from a scale where cetane or *n*-hexadecane = 100 and α-methylnaphthalene = 0.
- Lubricating oils are a mixture of long chain aliphatic hydrocarbons containing up to 50 carbon atoms and used for motor oils and lubricants. A portion of this cut will be separated and cracked to gasoline and kerosene feed stock.
- Heavy fuel oil is the next cut and contains aliphatic compounds with up to 70 carbon atoms. This cut was once commonly sold as fuel but has proven to be environmentally undesirable and as such is now hydro cracked to gasoline and kerosene feed stock.
- Resid is the very heavy high boiling point bottoms which are sent to a coker and cracked at high temperatures into heavy oil, gasoline, naphtha, and petroleum coke.

All the distillation cuts described above are mixtures of hydrocarbons and require additional distillation, desulfurization, and appropriate thermal or chemical processing to produce marketable finished products. The composition and quality of crude oils vary widely and the relative amounts and composition of each distillation cut will be different for different crudes. For example straight run naphtha from North Sea crude contains more than 60% more naphthenes than the same cut distilled from some Kazakhstan crudes and more than twice the aromatics of the same cut from some Australian crudes.

In a coal to liquids (CTL) plant the crude liquid is synthesized from ultra clean syngas over an iron catalyst in a slurry bed or fluidized reactor. Figure 1- 5 is a simplified process flow depiction of the synthesis and upgrade portion of a CTL plant.

Figure 1-5 Syngas to Fischer Tropsch Liquid Fuels

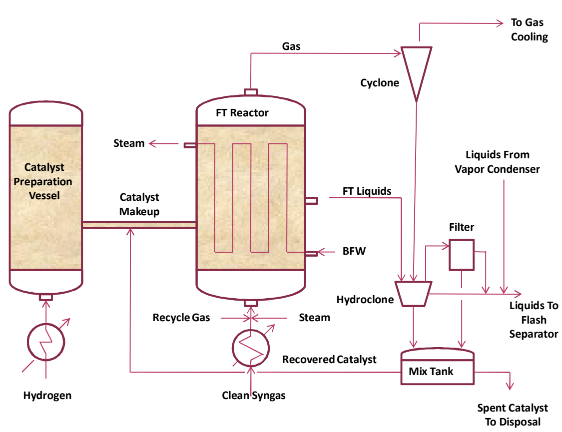


1.0 PLANT DESIGN

This process arrangement with slurry bed FT reactors is designed to maximize clean diesel production. The 25,000 bbl/d of liquid that would be produced from 12,000 tons per day of western Kentucky coal would be expected to be about 55% diesel and 45% distillate. The diesel quality will be very high quality and ready for sales. The distillate will require additional processing such as catalytic reforming and alkylation to raise the octane rating. This processing can be accomplished by adding those units to the CTL plant as Sasol has done or at an existing refinery as dictated by local economics. To better understand how these processes work together it is useful to first look at them individually:

- **Fischer-Tropsch Synthesis** There is at least four different types of reactors which have been used commercially for Fischer-Tropsch synthesis. Sasol started with the ARGE down-flow fixed bed tubular reactor in the 1950's. They added Synthol circulating fluidized bed reactors in the 1970's. In the 1990's Sasol replaced the earlier designs with large capacity Advanced Synthol fluidized bed reactors. Many of the proposed new CTL projects are planning to use what are called fixed slurry bed reactors. Designers are proposing plants with multiple 5,000 bbl/d reactors. The SASOL II plant now uses larger 20,000 bbl/d fluidized bed reactors. This report will describe a plant using fixed slurry bed FT reactors. Figure 1-6 is a simplified sketch of an FT Synthesis Unit based on the fixed slurry bed reactor option.

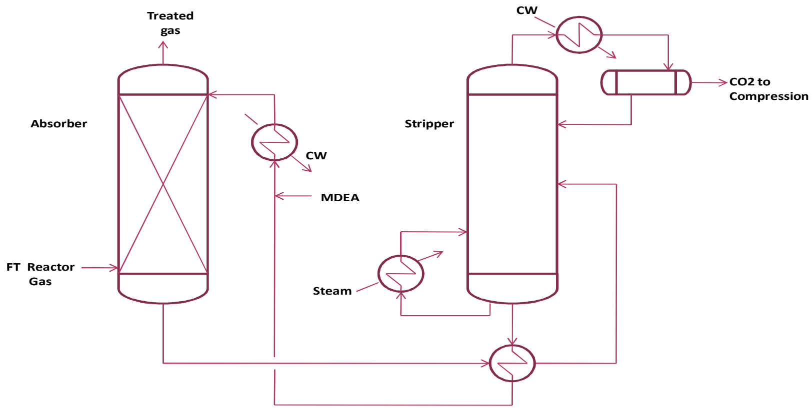
Figure 1-6 Fischer Tropsch Synthesis Unit



The slurry bed reactor operates full of hydrocarbon liquid in which fine iron catalyst particles are suspended. The ultra clean syngas must first be compressed to FT reactor pressure to make up for the pressure drop encountered in all the steps to upgrade the syngas quality from the outlet of the gasifier to the FT reactor inlet. The syngas is then heated, mixed with steam and recycled syngas which has been cleansed of CO_2 and bubbled up through the reactor bed. The carbon monoxide and hydrogen react in the presence of the iron catalyst at about 400°F and 375 psig to form liquid and gaseous aliphatic and olefinic hydrocarbons. Roughly 80% conversion can be achieved per pass through the reactor. The conversion is enhanced by recycling a large portion of the vapor, which has been hydrogen enriched by autothermal reforming, back to the reactor after processing it further. The heat released in these exothermic reactions is removed by generating 375 psig steam from the boiler feed water which is circulated in tubes suspended in the reactor fluid. The liquid hydrocarbon stream is cooled after leaving the reactor vessel and flows through a hydroclone separator to remove the suspended catalyst particles. The overhead from the hydroclone goes through a filter system to remove any remaining catalyst particles. After catalyst removal the FT liquid stream is combined with the condensate from gas cooling and sent to flash separation. The bulk of the recovered catalyst is returned to the reactor vessel. A small amount (about 6 tons per day from this size plant) is continuously blown down and must be disposed of. Fresh catalyst is fed to a catalyst preparation vessel where it is converted to a reduced form in a hydrogen atmosphere and then fed to the main reactor vessels. The vapor stream exiting the top of the reactor contains light hydrocarbons, un-reacted syngas, CO_2 and suspended catalyst particles. This vapor stream passes through a cyclone separator to remove the suspended catalyst particles prior to gas cooling. The catalyst from the cyclone is combined with the catalyst recovered from the liquid stream.

- **Gas Cooling** The vapor stream is cooled in four stages of heat exchange to reduce the temperature below 40°F to prepare it for CO_2 removal. A buildup of heavier hydrocarbons in the vapor stream could diminish the effectiveness of the amine solvent in the CO_2 removal step if they condense out in the absorber. Therefore the condensate formed after each cooling stage is collected and then mixed with the main liquid stream and sent to the flash separators and then to the Hydrocarbon Recovery Unit for further processing. The remainder of the vapor stream is sent to the methyl diethanolamine (MDEA) Unit for CO_2 removal.
- **Flash Separator** The FT liquid stream, after removal of catalyst particles by hydroclone separator and filter system and addition of vapor condensate from gas cooling, is further cooled to below 100°F and then reduced in pressure in two flash stages. The release of light hydrocarbon vapors in these flash stages further cools the liquid stream before it flows to the Hydrocarbon Recovery unit. A portion of this flash gas becomes fuel gas to be combusted in the gas turbine and rest of it is combined with the gas stream which is recycled via the autothermal reformers to the FT reactors.
- **CO_2 Removal** Because CO_2 is also produced in the FT reactor it would accumulate to unacceptable levels if allowed to remain in the recycle gas and could retard the FT reactions. A standard amine solvent system such as MDEA is used to remove the CO_2 from the vapor stream before recycling it back to the FT reactor. The CO_2-rich gas is fed to the bottom of a packed or tray absorber column and bubbles up through the column. Lean MDEA solvent is fed to the top and flows down. The counter current contact removes the CO_2 to very low levels in the treated gas and loads the solvent exiting the bottom with CO_2. A stripper column is used to regenerate the MDEA solvent as shown in Figure 1-7.

Figure 1-7 MDEA Unit



- **Recycle Gas Compression and Dehydration** The pressure drops resulting from flashing, heat exchange, amine scrubbing and other separation equipment requires boosting the recycle syngas pressure so that it will flow through the autothermal reformer and back into FT reactor. For this service reciprocal gas blowers are selected. Two trains with two 500 horsepower (hp) blowers in each train should be sufficient. The gas can be dehydrated with mol sieves. The aqueous oxygenates separated with the water are sent to the Hydrocarbon Separation Unit for further processing.

- **Hydrocarbon Separation Unit** This is a large area of the plant where all the liquid hydrocarbon streams are combined and then separated in fractionation columns into naphtha, distillate, and wax fractions or cuts. These three cuts require additional processing and are sent to a Product Upgrade Area for that purpose. The naphtha and distillate stream are processed in separate hydrotreaters and the wax stream is processed in hydrocrackers. The oxygenate streams are collected separately and either processed further for chemical production or they can be burned as fuel. The vapors are split into three gas streams. One portion is sent to the Hydrogen Recovery Unit where hydrogen is separated for use in the hydrotreating and hydrocracking reactors in the Product Upgrade Area. Another portion is separated for use as fuel gas. The remainder of the gas is sent to the auto thermal reformer for conversion back to syngas and then recycled back to the FT reactor.

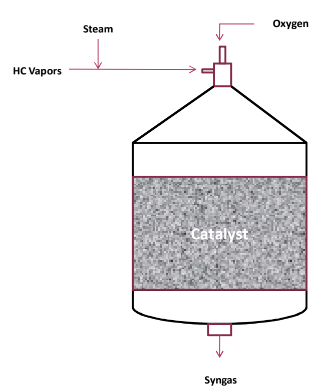
- **Hydrogen Recovery Unit** The hydrogen required for product upgrade is separated in multiple trains of pressure swing adsorption (PSA). PSA uses multiple vessels with fixed beds packed with mol sieve sorbent material. The sorbent holds large amounts of the gases that make up the vapor stream other than hydrogen at high partial pressures. The hydrogen passes through unchanged except for a small pressure drop. Each vessel stays online for the time it takes to reach maximum loading on the sorbent material while the 99% pure hydrogen is collected and sent to the Product Upgrade Area. After the sorbent is loaded the adsorber vessel is taken offline and depressurized. At lower pressure the sorbent material releases the other gases which are sent to the plant fuel system and the vessel is then purged before beginning another adsorption cycle. The adsorber vessels are cycled in a staggered sequence to result in continuous hydrogen flow.

- **Autothermal Reformer (ATR)** The recycle gas still contains a large amount of C_1 through C_4 hydrocarbons. Before recycling to the FT reactors these gases must be converted back into syngas. This is accomplished in autothermal reformers. The ATR is a refractory lined pressure vessel with a catalyst bed and a specially designed burner system on top. The advantage of ATR is that both catalytic partial oxidation and steam reforming of the syngas/steam mixture take place in the same vessel. The steam reforming is endothermic and requires heat addition. The catalytic partial oxidation is exothermic and provides a portion of the heat energy for the steam reforming. The resulting higher efficiencies permit the use of smaller, lower cost reactor vessels and shorter startup times. Companies like Haldor Topsoe have developed ATR designs that include both proprietary burner configurations and proprietary catalyst. Figure 1-8 is a simplified sketch of that type of vessel. Using methane for an example the ATR reactions can be represented by the following:

$$CH_4 + \tfrac{1}{2}O_2 \longrightarrow CO + 2H_2 \qquad \text{Exothermic}$$

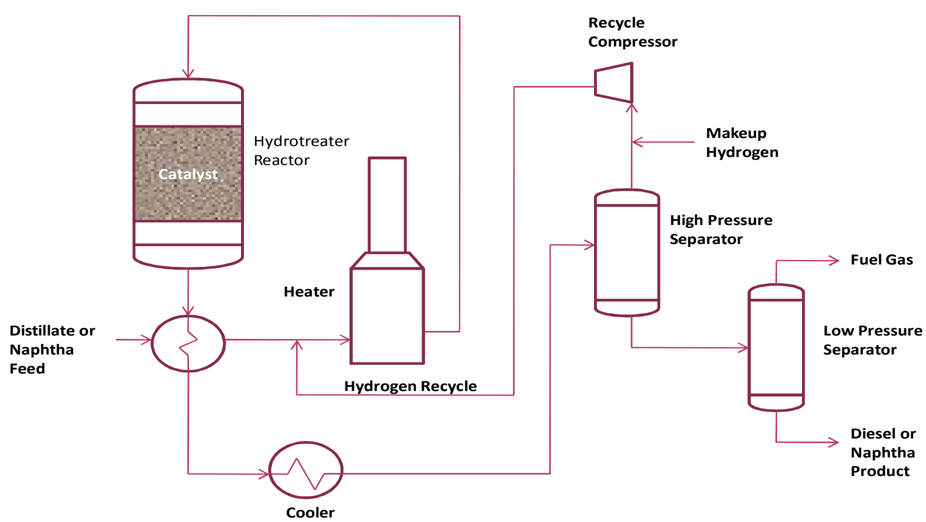
$$CH_4 + H_2O \longrightarrow CO + 3H_2 \qquad \text{Endothermic}$$

Figure 1-8. Autothermal Reformer



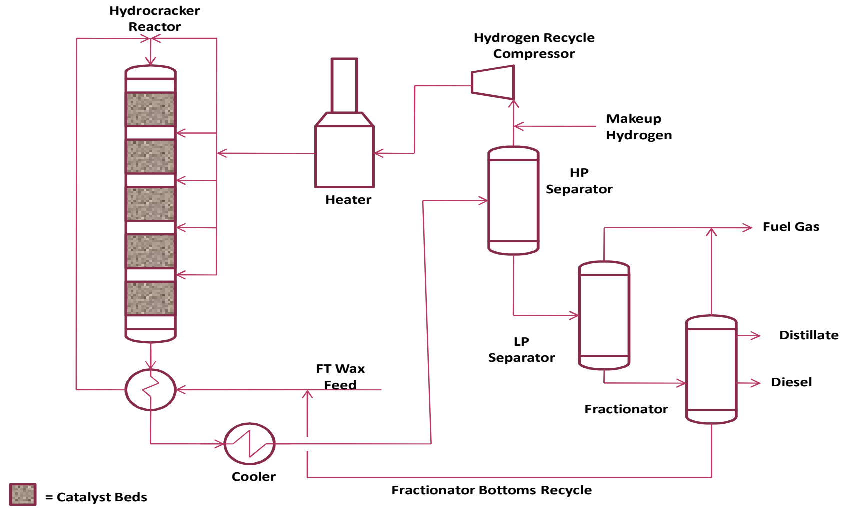
- **Hydrotreating Units** Both the naphtha and distillate fractions from the FT Hydrocarbon separation Area still contain too many unsaturated hydrocarbon compounds and have H/C ratios that are too low to provide stable fuels. This is corrected by sending each stream to a dedicated hydrotreating unit where they are reacted with hydrogen over a catalyst. Because they were produced from ultra clean syngas the removal of impurities is not required as is the case with similar feeds in a crude oil refinery. The equipment will be similar for both the naphtha and distillate hydrotreating processes but the temperature, pressure, amount of hydrogen, and type of catalyst required will be different for each stream. Figure 1-9 is a simplified flowsheet for the hydrotreating required in either case. The feed is mixed with hydrogen, heated, and fed to the top of a downflow fixed bed reactor where hydrogenation and saturation occur. Unreacted hydrogen is separated in a high pressure separator, compressed, and recycled to the reactor. The liquid flows to the low pressure separator where liquefied petroleum gas (LPG) and light gases are recovered off the top for use as fuel. The liquids off the bottom of the low pressure separator go to storage or further processing. As mentioned above the diesel from its low pressure separator can now be sold as commercial diesel. The naphtha from its low pressure separator will require additional processing such as catalytic reforming or alkylation before use as gasoline blend material.

Figure 1-9 Hydrotreating Process For FT Naphtha or Distillate Liquids



- **Hydrocracking Unit** The heavy wax fraction from the Hydrocarbon Separation Area can be converted into a mixture of smaller molecules which can then be fractionated into naphtha and diesel. This is accomplished with catalytic hydrocracking in one or more reactor vessels with multiple fixed reactor beds. Heated hydrogen is mixed with the wax feed and with the effluent from each successive reactor bed stage. The initial stages are packed with catalyst to result in hydrogenation of the wax feed. Subsequent stages are packed with hydrocracking catalyst that will support the break up the long hydrocarbon chains into smaller mole cules and also dealkylate aromatics. Figure 1-10 on the following page is a simplified process flow for the hydrocracking of this FT wax stream.

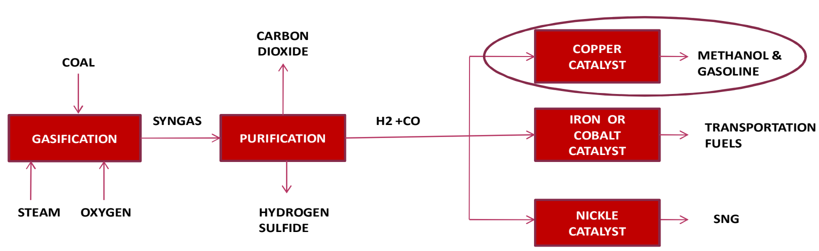
Figure 1-10. Hydrocracking Process For FT Wax Stream



1.1.2 Gasoline from Methanol via Gasification

A second commercially available method for producing liquid fuels from coal is to convert the coal derived syngas to methanol and then convert that methanol to gasoline. In the early 1970's Mobil developed the methanol to gasoline (MTG) process. MTG takes the same ultra clean syngas that could feed an FT reactor and converts it to gasoline in a series of catalytic dehydration steps called shaped dehydration. Methanol is first converted to dimethyl ether (DME) over an alumina catalyst. Then the DME is converted to light alkenes over a ZSM-5 zeolite catalyst. The light alkenes link up to form branched alkanes, branched alkenes, naphthenes and aromatics in the proper percentages to make a hydrocarbon mixture that is fully compatible with conventional gasoline. Figure 1-11 shows the selection of the methanol synthesis route for production of gasoline from coal.

Figure 1-11. Select Methanol to Gasoline Option



The starting point for making gasoline from coal by the MTG process is gasifying the coal and purifying the resulting syngas. The steps to accomplish this have all been described in the Part I Report. The next step is to convert the clean syngas to methanol (CH_3OH). Lurgi, ICI, and

1.0 PLANT DESIGN

Mitsubishi are a just a few of the companies that have commercial processes available for this service Two natural gas reforming based methanol plants were constructed in New Zealand in the early 1980's using Davy Mckee technology. The first was a stand-alone 1500 ton per day plant located at Waitara and the second consisted of two 2600 ton per day trains located at Motunui. The Motunui Plant included a MTG Unit capable of producing 2200 tons or 14,000 barrels of gasoline per day. Although the Motunui plant reformed natural gas to provide the syngas for feed to the Methanol Synthesis Unit, purified syngas from coal could be processed with the same equipment design. The MTG Unit was operated until 1996 when it was taken out of service due to the availability of low priced crude based gasoline and the higher product value of methanol at that time.

Syngas can be converted to methanol over a copper-zinc (Cu-Zn) catalyst in either isothermal or adiabatic reactors. The isothermal (constant temperature) reactor has the catalyst in vertical tubes which are suspended in boiler feed water so that the heat generated by the exothermic reaction can be continuously removed by the heating of the boiler feed water in order to generate 550 psig steam. Small temperature changes in the boiling water around the tubes of the isothermal reactor will produce large pressure increases in the steam drum which provides a measure of control. The adiabatic (constant heat) reactor requires multiple stages with external heat exchange between each stage. In either case it is important to protect the catalyst from high temperatures that would cause irreversible damage due to crystallization of the catalyst.

The reactions for either type of reactor are the same and can be represented by the following equations:

$$CO + 2\ H_2 \xrightarrow{\text{Cu-Zn Catalyst}} CH_3OH + \text{heat}$$

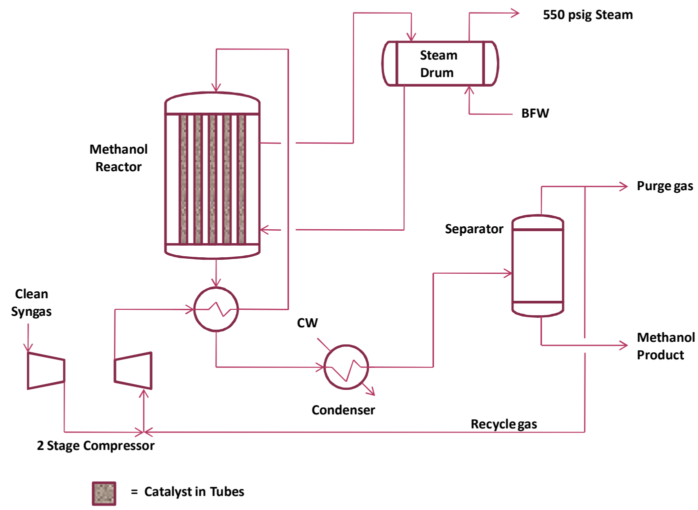
$$CO_2 + 3\ H_2 \xrightarrow{\text{Cu-Zn Catalyst}} CH_3OH + H_2O + \text{heat}$$

It can be seen from the equations that less hydrogen is required for the conversion of carbon oxides as compared to the conversion to methane. Methanation of carbon monoxide to methane requires three hydrogen molecules versus two hydrogen molecules for methanol synthesis from carbon monoxide. Therefore, less shift conversion will be required upstream for the methanol case to minimize the purge from the recycle stream. If the plant includes a Methanation unit for the co-production of SNG the purge gas can be mixed with the methanation inlet gas. Otherwise the purge gas may be used as fuel.

Figure 1-12 is a simplified flow for isothermal conversion of syngas to methanol. The clean syngas is compressed to 750 psig, preheated to 500°F and fed to the top of the reactor. The reactor effluent is cooled, condensed and separated into methanol and recycle/purge gas.

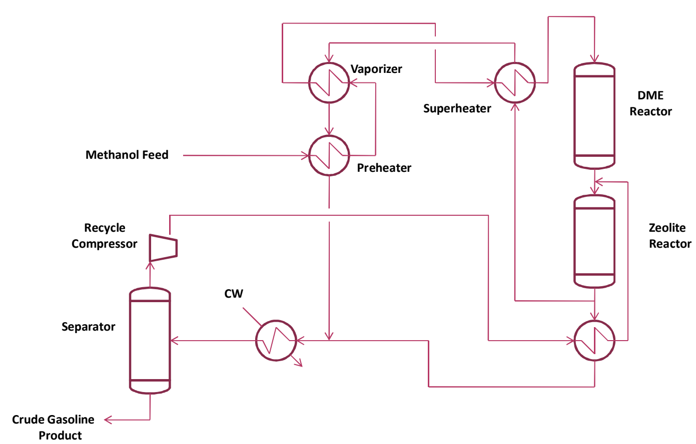
1.0 PLANT DESIGN

Figure 1-12. Methanol Synthesis



The crude methanol is then converted to gasoline using the MTG process. Figure 1-13 is a simplified representation of the process flow for that process.

Figure 1-13. Methanol to Gasoline process



The feed methanol is heated, vaporized and superheated to about 600°F before feeding it to the DME reactor where it is dehydrated and converted to dimethyl ether over an alumina catalyst. The reaction is represented by:

$$2CH_3OH \longrightarrow CH_3OCH_3 + H_2O$$

1.0 PLANT DESIGN

Because the reaction is reversible about 75% of the methanol is reacted to form an equilibrium mixture of DME, methanol, and water. This stream gets mixed with recycled gas from the product separator and fed to the zeolite reactors where it is converted to gasoline. At this stage the synthetic gasoline contains as much as 6% durene and requires additional processing. Durene is an undesirable high melting point material that is normally below 0.3% in conventional gasoline. Durene can be minimized by isomerization to isodurene. The synthetic gasoline is first distilled to light, middle and heavy fractions because the durene concentrates in the heavy fraction. The heavy fraction is passed through an isomerization reactor stripped of light ends and blended with the other fractions as required to meet gasoline product specifications.

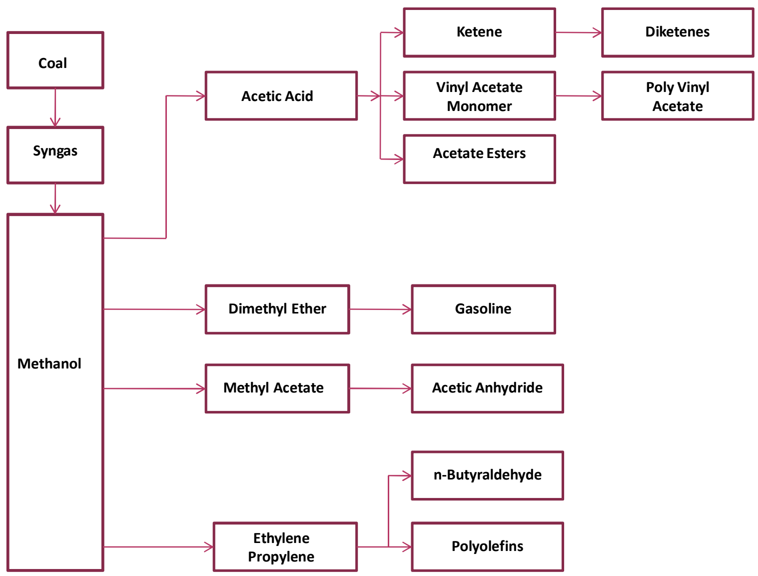
This synthetic gasoline compares very favorably with conventional gasoline in all respects. It achieves an octane rating of 92 to 94, has essentially no sulfur and less than 25% of the benzene content of conventional gasoline.

1.1.3 Chemicals from Coal Gasification

This report has described two different methods for producing liquid transportation fuels from coal gasification derived syngas. The FT route would produce about 25,000 barrels per day of liquid hydrocarbons, about 55% of which would be ready for market diesel and the remainder would be distillate that could be processed into gasoline and oxygenates with value as chemical feed stocks. The methanol to gasoline route would take essentially the same syngas and convert it to about 32,000 barrels per day of gasoline and 340 tons per day of LPG. Both Fischer-Tropsch synthesis and methanol synthesis present the opportunity to produce a wide range of chemicals. As an example Sasol produces nearly 200 different products in their three coal gasification facilities in South Africa in addition to their main products of diesel, gasoline, jet fuel, and lube oils. . In another example the Great Plains Coal Gasification Plant in North Dakota ("Great Plains") which uses neither FT nor MTG produces eight different byproducts in addition to its main SNG product and is performing research on producing additional byproducts. Great Plains does operate a small 15 ton per day methanol plant to produce makeup solvent for their Rectisol Syngas Purification Unit

The chemical industry worldwide has long been based on steam reforming either natural gas or refinery gases to produce syngas. Ammonia and urea are made from syngas as is methanol which becomes a feed stock for numerous other chemicals. In fact the chemicals made from methanol are too numerous to describe in this report. A sample is shown in Figure 1-14.

Figure 1-14. Chemicals from Methanol



Source: Eastman Company at Gasification Technologies Workshop, 2008

From 2003 through 2007, 20 ammonia plants and 6 methanol plants in the U.S. have shut down. The bulk of the US production was based on steam reforming natural gas to produce the syngas necessary for making these chemicals. The sharp rise in U.S. natural gas prices has made those plants non-competitive. Foreign production in areas where natural gas is relatively inexpensive like the Middle East and former Soviet Union has replaced the U.S. production. A number of negative impacts have been resulting including loss of U.S. jobs, trade imbalance, and higher end product cost due to longer transportation distances and worldwide competition for the products.

Companies like Eastman appear to be convinced that the future development in their industry will be tied to gasification technology. Coal to chemicals appears to have the best chance of being the largest growth sector for coal gasification development. There is no indication that natural gas price or availability will return to pre-2000 levels. While the concern for lack of clear government direction regarding carbon capture and sequestration is hindering the expansion plans for electric power and SNG companies, its impact on coal to chemical plants is smaller. The cost to capture and compress CO_2 in coal to chemicals plants has been predicted by the Massachusetts Institute of Technology (MIT) to be half the cost for an integrated gasification combined cycle (IGCC) and a quarter the cost for pulverized coal fired power plants. This is because sulfur removal is required to very low levels prior to chemical synthesis. The processes that accomplish this maximum sulfur removal also make CO_2 capture simpler and permit capture at higher pressures resulting in lower compression requirements. Finally coal to chemicals plants should be easier to permit since the carbon in the non-fuel products stays there and is not converted to carbon dioxide by an end user.

1.1.4 Power Generation from Coal Gasification

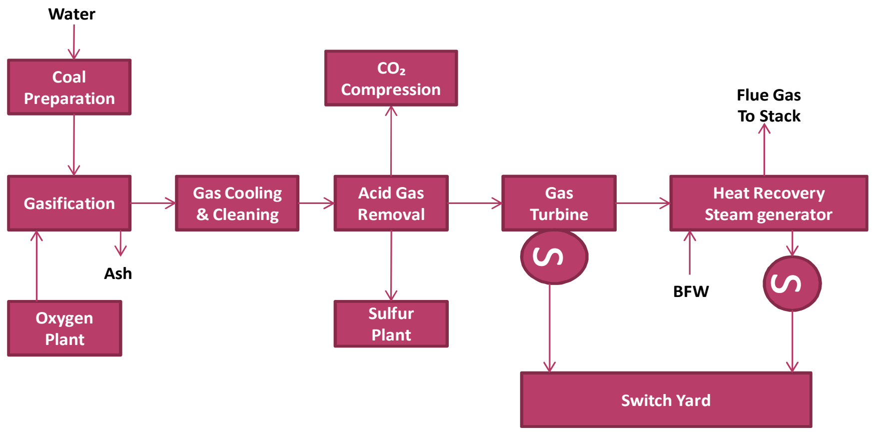
Electric power generation from coal gasification known as IGCC (integrated gasification combined cycle) was expected to be one of the major applications of gasification technology in part because of sharp rises in natural gas pricing. The United States entered this decade expecting to build 300 gigawatts (GW) of new electric power generating capacity to meet the expected demand growth. Over 88% of that 300 GW was expected to be gas-fired because natural gas supplies appeared adequate, prices were stable, and there were environmental advantages. In August, 2005 the wellhead price for gas jumped to $7.65 per MMBtu, a 43% increase over the previous August. The Henry Hub price swelled to $12 per MMBtu by October of that year. Pricing was beginning to reflect diminishing availability of natural gas and the level of difficulty in finding and producing additional supplies. As a result power companies began comparing the complexities of permitting new pulverized coal (PC) fired plants with the more environmentally friendly but higher cost IGCC.

The Wabash IGCC (“Wabash”) in Indiana utilizing ConocoPhillips gasification technology and TECO’s Polk County IGCC Plant in Florida utilizing General Electric (GE) gasification technology, which were both partially funded by U.S. Department of Energy (DOE), had ten years of problem solving operations each by 2006. Both plants are still in full commercial operation today. The environmental and efficiency advantages of both these technologies over standard PC plants have been well documented. The DOE had proposed to take IGCC a step further when they sponsored the government-industry FutureGen Consortium to design and build a near zero emission coal gasification based power plant. This was to be accomplished by shift converting all the syngas to hydrogen and carbon dioxide and then removing 99% of the sulfur and 95% of the carbon dioxide with a two stage acid gas removal process. The predominantly hydrogen fuel would result in extremely low emissions when combusted in the gas turbine. DOE has since withdrawn support for FutureGen.

Although very similar to other coal gasification plants the IGCC has several differences. The oxygen fed to the gasifiers in an IGCC plant does not have to be as pure as that required for SNG production. SNG plants require 99.5% pure oxygen because additional nitrogen and argon would dilute the heating value of the product gas. IGCC plants purposely dilute the feed to the gas turbine to reduce nitrogen oxide (NO_x) emissions. Another difference is that standard IGCC does not require a Shift Conversion Unit. Carbon monoxide has nearly the same heating value as hydrogen and is probably a better turbine fuel. IGCC could shift some or all of the syngas if it was required to minimize CO_2 emissions from the turbine. However this would increase the CO_2 load on the Acid Gas Removal Unit and CO_2 Compressor. Finally the level of sulfur removal would normally be less for IGCC. Sulfur is removed to ultra low levels to protect the catalyst in other plants. There is no such requirement in IGCC plants. However, Wabash demonstrated a 97% reduction in sulfur emissions with their IGCC over the PC unit it replaced.

Figure 1-15 is a simplified version of an IGCC. This flow scheme shows CO_2 going to compression. However, since carbon capture is not yet required by law in every state some IGCC projects have been filed showing only space to add a CO_2 absorber and compressor at a later date.

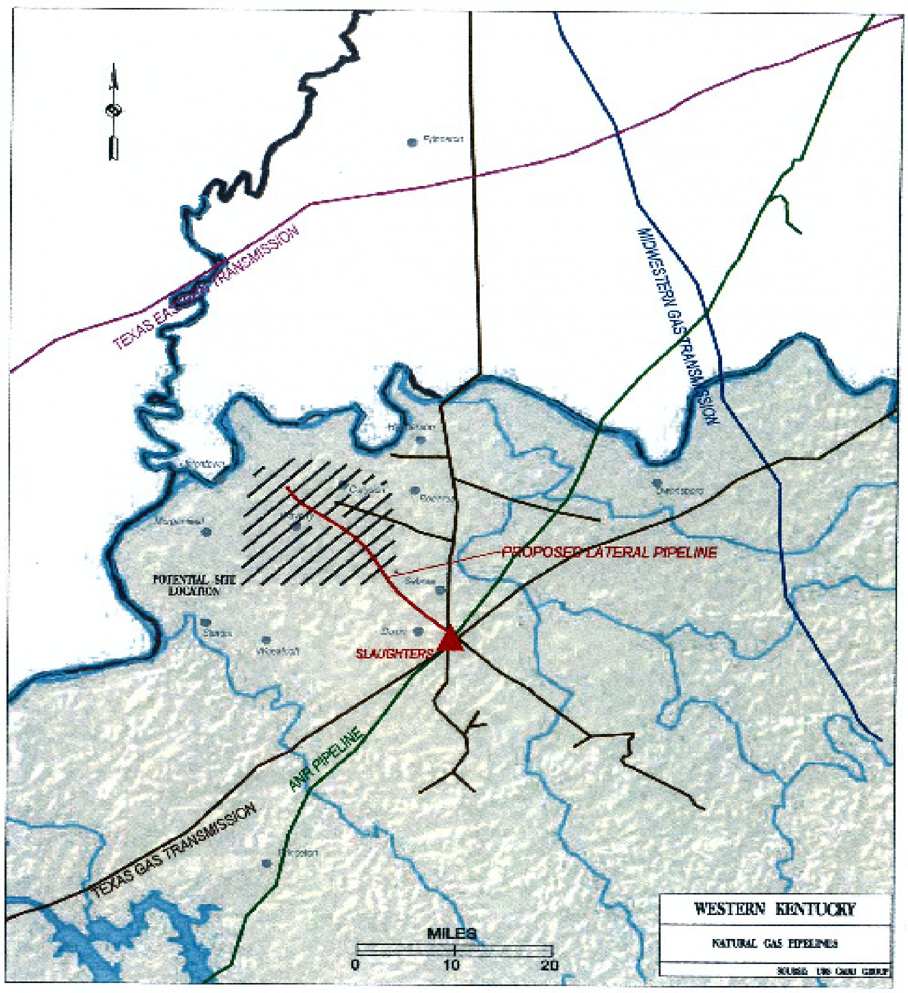
Figure 1-15. Integrated Gasification Combined Cycle



2.0 SNG PIPELINE

For the purpose of this study four major interstate natural gas pipelines were found to be located within a 50-mile radius of the proposed coal gasification facility. ANR Pipeline Company ("ANR"), Midwestern Gas Transmission Company, Texas Eastern Transmission, and Texas Gas Transmission, L.L.C. operate these large diameter pipelines. They transport natural gas supply to markets throughout the Midwest and Northeast United States and as such could potentially be used to transport any SNG produced by the gasification facility to these same markets. The map in Figure 2-1 illustrates the general location of these pipelines in relation to potential coal gasification facility site location discussed in this report.

Figure 2-1 Locations of Natural Gas Pipelines



2.0 SNG PIPELINE

2.1 TRANSPORTATION INTERCHANGEABILITY OF SNG AND NATURAL GAS

It can be assumed that the synthetic natural gas (SNG) produced from the coal gasification facility will meet the specifications for gas quality identified a typical pipeline company's transportation tariff. The following is a listing of some gas quality standards typically identified in such tariffs. The following standards were taken from ANR Pipeline's tariff and for the purposes of the report may be considered representative of the other pipelines shown since they all typically interconnect and exchange volumes of gas. The gas to be transported:

- Shall have a heat content not greater than 1200 Btu's per cubic foot nor less than 967 Btu's per cubic foot when determined on a dry basis
- Shall be commercially free of objectionable odors, dust, water, and any other solid or liquid matter which might interfere with it's merchantability or cause injury
- Shall not contain more than four (4) parts per million (one quarter grain per one hundred (100) cubic feet of gas) of hydrogen sulfide in the Mainline Area facilities
- Shall not contain more than twenty (20) grains of total sulfur (including the sulfur in any hydrogen sulfide and mercaptans) per one hundred (100) cubic feet of gas
- Shall not at any time have an oxygen content in excess of one percent (1%) by volume and the parties hereto shall make every reasonable effort to keep the gas free of oxygen
- Shall be free of water and hydrocarbons in liquid form and shall in no event contain water vapor in excess of seven (7) pounds per million cubic feet of gas
- Shall not contain more than two percent (2%) by volume of carbon dioxide
- Shall be delivered at a temperature not in excess of one hundred twenty (120) degrees Fahrenheit or less than forty (40) degrees Fahrenheit
- Shall not contain more than three percent (3%) by volume of nitrogen
- Shall not contain any toxic, hazardous materials or substance, or any deleterious material potentially harmful to persons or to the environment
- Shall meet the hydrocarbon dew points limit defined in the tariff

2.2 LOCATION OF PIPELINE INTERCONNECT

A gasification plant will not likely be located immediately adjacent to a major interstate pipeline facility. In this study the closest large diameter pipelines are operated by ANR and Texas Gas Transmission ("TGT"). It was therefore proposed that the SNG from the coal gasification plant be transported by a new pipeline to a point of interconnect with either or both ANR and TGT near Slaughters, KY (see figure 2-1). It is at this point where the large diameter pipeline facilities of ANR and TGT are adjacent to each other. Connecting to both pipelines at a

2.0 SNG PIPELINE

common point will provide increased flexibility and capacity for subsequent transportation of the SNG at little incremental cost. A new pipeline to the existing pipeline facilities of Midwestern Gas Transmission Company and/or Texas Eastern Transmission could also connect the proposed gasification plant. The market, the pipeline transporter, and the coal gasification project developer will ultimately determine the actual delivery point location(s).

2.3 LATERAL DESIGN ALTERNATIVES

A new pipeline approximately 30 miles in length will be required to connect the gasification plant to ANR or TGT at Slaughters, KY as shown in figure 2-1. For the purposes of this report, it was decided to focus on a pipeline lateral extending from the proposed gasification facility to the existing ANR pipeline as an example design. The gasification plant will produce approximately 175 MMcfd of SNG. It is assumed that SNG will leave the plant at 1000 psig. ANR's Maximum Allowable Operating Pressure (MAOP) at this location is 858 psig. For design purposes, it should be assumed that the SNG would be delivered to ANR at pressures no less then the MAOP as pressures greater than ANR's MAOP can be regulated down at the point of interconnection. Custody transfer equipment will also be installed at the point of interconnection to measure and monitor the quantity and quality of the SNG. The facility designs and associated costs in this report were prepared assuming the connecting pipeline will be either a 20-inch diameter pipeline or a 24-inch diameter pipeline. To allow for future growth at the gasification site, a second plant would need to be developed and placed in operation. This second plant could increase the SNG produced at the site from 175 MMcfd for one plant to 350 MMcfd for two plants. Again assuming 1000 psig is available at the plant outlet, the resulting delivery pressure to ANR and other operation parameters are summarized in Figure 2-2 on the following page.

2.0 SNG PIPELINE

Figure 2-2 Summary of Proposed Pipeline Operating Parameters

Alternative Design	Number of plants	Pipeline Length (miles)	Plant Outlet Pressure (psig)	ANR Delivery Pressure (psig)	ANR Delivery Volume (MMcfd)
175 MMcfd Supply - 20" Pipeline to ANR Pipeline	1	30	1000	940	175
350 MMcfd Supply - 20" Pipeline to ANR Pipeline	2	30	1000	762	350
175 MMcfd Supply - 24" Pipeline to ANR Pipeline	1	30	1000	976	175
350 MMcfd Supply - 24" Pipeline to ANR Pipeline	2	30	1000	910	350

As previously discussed, the delivery pressure, for design purposes, must be equal to or greater than the ANR pipeline MAOP of 858 psig. Therefore, as shown in figure 2-2, a 20-inch diameter pipeline will provide a sufficient delivery pressure for a one-plant design, while a 24-inch diameter pipeline will be required for a two-plant design. The flow diagrams illustrated in Figure 2-3, Figure 2-4, Figure 2-5, and Figure 2-6 depict the operation of the four alternative designs for the new connecting pipeline.

2.0 SNG PIPELINE

Figure 2-3 Flow Design for One Plant with 20" Pipeline

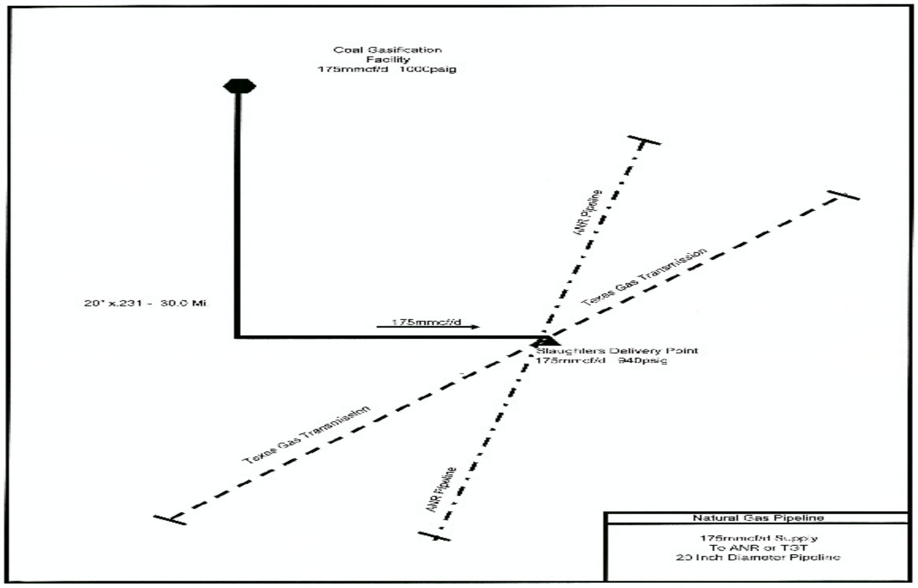
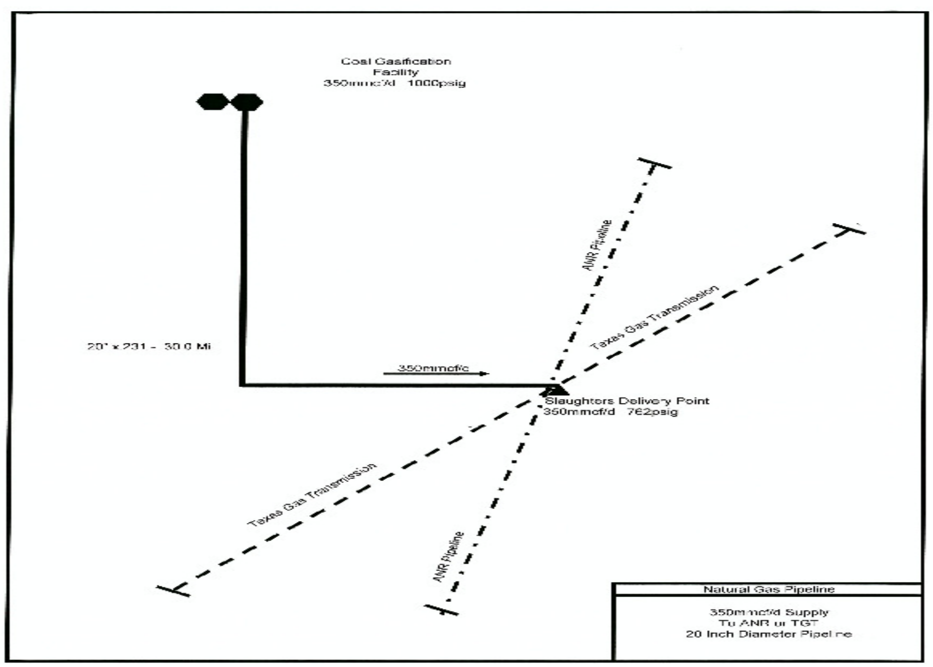


Figure 2-4 Flow Design for Two Plants with 20" Pipeline



2.0 SNG GAS PIPELINE

Figure 2-5 Flow Design for One Plant with 24" Pipeline

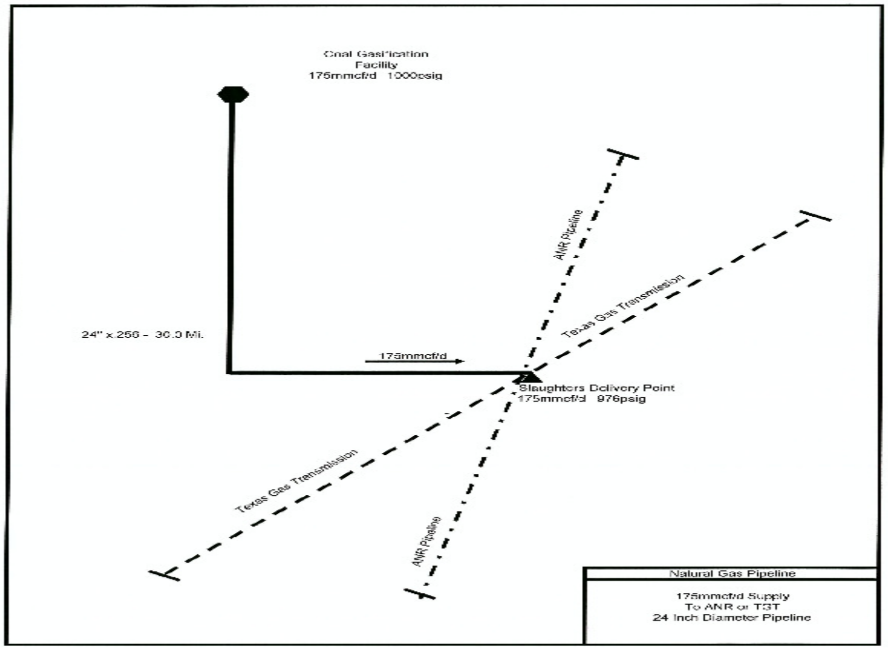
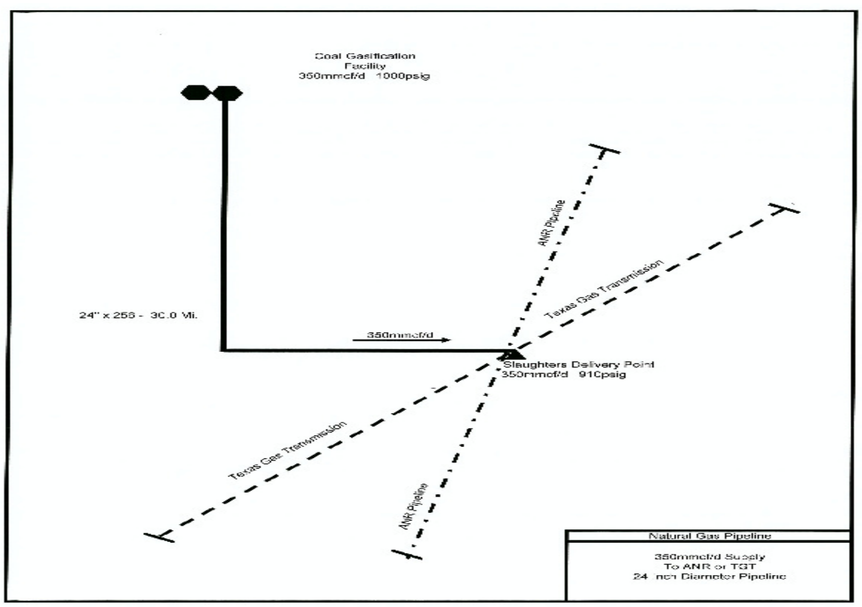


Figure 2-6 Flow Design for Two Plants with 24" Pipeline



2.0 SNG GAS PIPELINE

2.4 CAPITAL COST

It is currently estimated that the cost of the 20-inch diameter pipeline will be approximately $34 million (2008 dollars). In addition, a meter station with an estimated cost of approximately $2 million will be required at the point of interconnection with ANR. The total cost of the connecting pipeline and meter station is therefore estimated to be approximately $36 million. Both the pipeline and meter station costs are likely change by the time the gasification plant is constructed and placed into operation. These costs need to be included in the overall feasibility evaluation of the coal gasification project.

Flow studies were also prepared to identify the conceptual design of a connecting pipeline if two plants were eventually constructed and placed into operation. With two plants in operation, the SNG volume that would require transportation would increase from 175 MMcfd to 350 MMcfd. This increase will require the connecting pipeline to increase from a 20-inch diameter pipeline to a 24-inch diameter pipeline. It is estimated that the cost of the larger pipe will be approximately $39 million (2008 dollars). In addition, a meter station with an estimated cost of approximately $2 million will be required at the point of interconnection with the interstate pipeline. The total cost of the larger diameter pipeline and meter station is estimated to be $41 million or $5.0 million more than the smaller 20-inch diameter pipeline. The larger diameter pipeline can transport over two times the volume of the smaller pipeline at a relatively small incremental cost. The project developers will ultimately decide the most beneficial design.

2.5 COST OF SERVICE

The capital cost of the connecting pipeline will add to the cost of the gas to be sold to the prospective market. The project developers will ultimately use their own economic models to place a cost for transporting the SNG in the connecting pipeline. However, for this report a general rule of thumb was used to determine a potential transportation cost. It was estimated that for a one-plant design where a 20-inch diameter pipeline is placed into operation, the unit cost of transportation would be approximately $0.11 per one thousand cubic feet ($0.11/Mcf). This assumes the coal gasification plant operates 90% of the year producing approximately 175,000 Mcf per day. It also assumes a 2008 cost for the connecting pipeline of approximately $36 million.

In the case where two plants are ultimately placed into operation and a 24-inch diameter-connecting pipeline is installed, the unit cost of transporting is estimated to be approximately $0.06 per one thousand cubic feet ($0.06/Mcf). Again, this assumes that both plants operate 90% of the year producing 350,000 Mcf per day. It further assumes an estimated 2008 cost of the connecting pipeline of approximately $41 million.

3.0 ENVIRONMENTAL PERMITTING

3.1 AIR PERMITTING

State and federal air permits in Kentucky are administered by the Kentucky Division for Air Quality (DAQ). The division is part of the Kentucky Department for Environmental Protection and is part of the Environmental and Public Protection Cabinet. The type of permit and level of detail required to permit a new source of air pollution in Kentucky depends largely on the project's potential to emit (PTE) regulated air pollutants. The various types of coal gasification plants can have dramatically different emissions. For example, if SNG is produced, the emissions during routine operations will be somewhat minimal – and the air permitting requirements may be less. In contrast, if syngas or SNG is combusted in turbines for the production of electricity, those additional combustion emissions increase the total facility emissions significantly, and could trigger the highest level of preconstruction air permitting requirements. Since this feasibility study is dealing with multiple gasification conceptual stage project ideas, this section will address permitting requirements in general, and highlight issues that may be of concern for a coal gasification plant located in western Kentucky.

3.1.1 General Air Permitting Requirements

Generally, a construction permit must be obtained before construction can begin. For large facilities such as the proposed gasification plant, it can often take 6 to 12 months to prepare the permit application, and another 6 to 12 months for the state agency to review it. The type of pre-construction permitting review required is dependent on the overall magnitude of emissions. In general, the following emissions/permit thresholds apply in Kentucky:

Nothing is required (no registration or permit) if a source's PTE is:

- less than 2 tons per year (tpy) of a Hazardous Air Pollutant (HAP);
- less than 5 tpy of combined HAPs;
- less than10 tpy of all regulated air pollutants; and
- the source is not subject to a New Source Performance Standard (NSPS) or National Emissions Standard for Hazardous Air Pollutant (NESHAP).

A state origin (minor source) permit is required if a source's PTE is:

- less than 10 tpy of a HAP;
- less than 25 tpy of combined HAPs; and
- greater than 25 but less than 100 tpy of a regulated air pollutant subject to an applicable regulation that does not specify the method of compliance.

3.0 ENVIRONMENTAL PERMITTING

A Title V (major source) operating permit is required if a source's PTE is:

- greater than 10 tpy of any HAP;
- greater than 25 tpy of combined HAPs; or
- greater than 100 tpy of any regulated air pollutant; and
- the source's PTE is not limited below these thresholds by a permit (conditional major) or prohibitory rule.

A Federal New Source Review permit is required if the sources PTE is above the "major" source threshold, typically 100 tons per year.

The longest lead time permit commonly needed to obtain an air permit is associated with a Federal New Source Review permit. The specific type of federal pre-construction permitting review required is dependent on the attainment status of the area where the project is planned and the overall magnitude of project emissions. These issues are discussed in Sections 3.1.2 through 3.1.4.

3.1.2 National Ambient Air Quality Standards (NAAQS) Attainment Status

The type of federal pre-construction permitting review required is dependent on the attainment status of the plant location for each criteria pollutant emitted. The Clean Air Act, which was passed in 1970 and last amended in 1990, requires the EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants that cause adverse affects to public health and the environment. The EPA has set NAAQS for the six common air pollutants, also called "criteria" pollutants. These criteria pollutants are carbon monoxide, nitrogen dioxide, ozone, lead, sulfur dioxide and particulate matter.

If an area is in attainment for a specific pollutant, it means that measured concentrations of that pollutant in the air are less than the NAAQS. Non-attainment areas are regions where the concentration of one or more criteria pollutants exceeds the level set by the federal air quality standard as protective of human health.

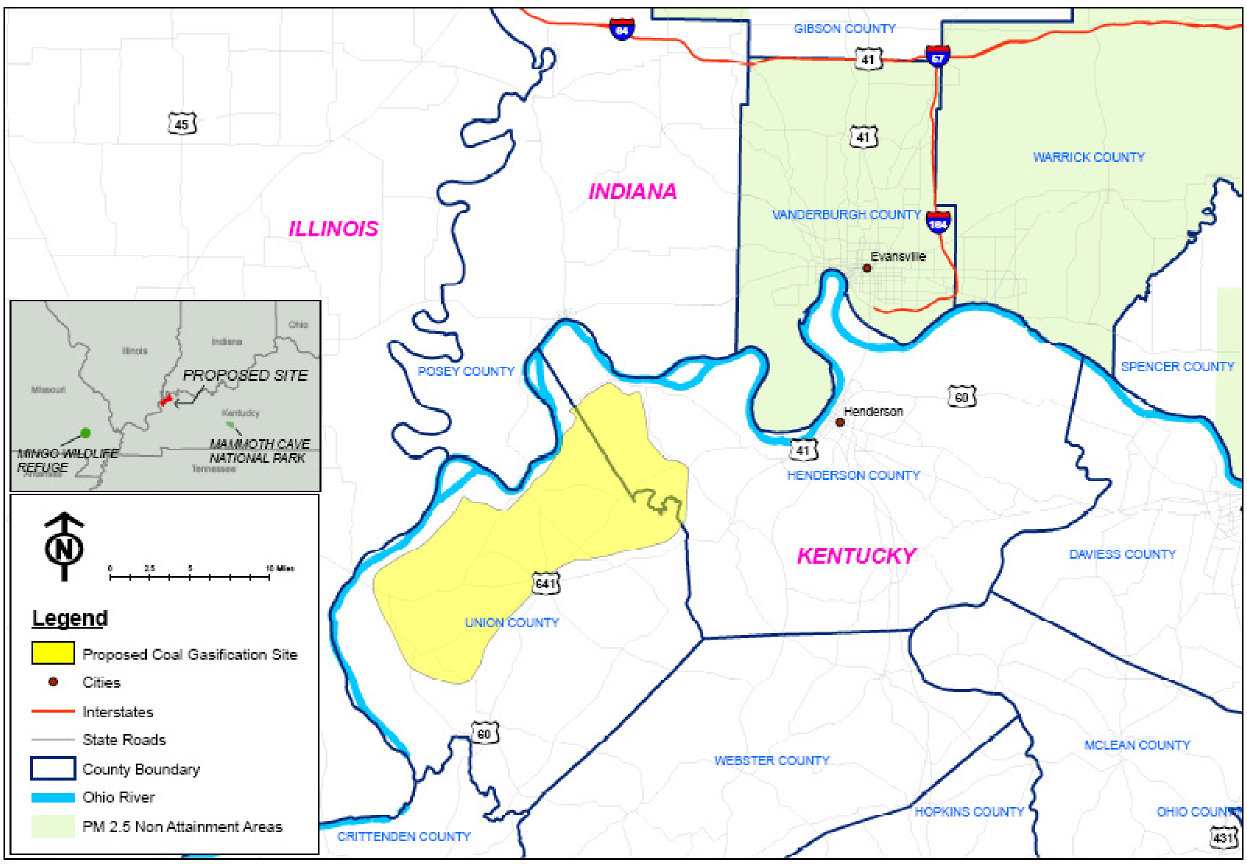
All counties in Kentucky are designated as attainment for NO_x, CO, and lead. Most of the Kentucky counties are in attainment for the other pollutants as well including Union, Henderson, and Webster Counties, where the preferred plant site could located. The only counties not in attainment are some of the counties near Louisville, Cincinnati, and Ashland, which are designated as non-attainment for SO_2, eight-hour ozone, and/ or $PM_{2.5}$

The area in Kentucky that is being considered in this study as a potential location for a gasification project site is in attainment of the NAAQS for all criteria pollutants. Therefore, if the proposed facility is located in the proposed study area and is classified as a major source, it will undergo Prevention of Significant Deterioration (PSD) review, as described below, rather

3.0 ENVIRONMENTAL PERMITTING

than the more onerous Non-Attainment New Source Review (NAA-NSR). There are currently several counties located across the Ohio River in Indiana that are currently designated as non-attainment for the new $PM_{2.5}$ standard. As previously discussed only new facilities constructed within the non-attainment areas have additional permitting and offset requirements. However, a project constructed in an attainment area, such as the proposed gasification facility, that could hinder further reasonable progress towards attainment of the NAAQS in nearby non-attainment areas, like those existing in Indiana, could receive opposition from local citizen or governmental groups. Figure 3-1 illustrates the proximity of $PM_{2.5}$ non-attainment areas to the potential gasification site.

Figure 3-1 Potential Gasification Site and Regional Areas Sensitive to Air Pollution



3.0 ENVIRONMENTAL PERMITTING

3.1.3 Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

New Source Review permitting is triggered when emissions associated with a new major source are "significant". The major source threshold is 100 tons per year of any regulated pollutant for 28 named source categories, or 250 tons per year of any regulated pollutants if the source is not one of the named categories. Most types of gasification facilities will fall in to one of these 28 named source categories which include such sources as fossil fuel fired steam electric plants of more than 250 MMBtu/hr heat input, or a combination of fossil fuel fired boilers totaling greater than 250 MMBtu/hr, fuel conversion plants, chemical plants, and sulfur recovery plants.

Once a air emissions from a new source is classified as "significant" for at least one regulated attainment or non-criteria pollutant, all pollutants for which the area is classified as attainment, and which are emitted in amounts greater than the significant emissions levels in the table below are also subject to PSD review.

Table 3-1 PSD Significant Net Emissions Rates

Pollutant	PSD Significance (tons/yr)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter/PM_{10}/$PM_{2.5}$	25/15/10
Ozone (VOC)	40
Lead	0.6
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (TRS, including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10

Based on a review of other SNG permits (Secure Energy, Decatur, IL 4/6/07) and emissions levels associated with proposed or permitted IGCC plants, it is possible that a coal gasification plant *could* be designed with emissions less than 100 tons per year for all pollutants. Two of the potential pollutant emissions commonly associated with SNG plant operations, that will in all likelihood have to be carefully controlled and monitored in order for the facility to stay below the major source threshold, are emissions of SO_2 during startup events and emissions of CO from the CO_2 venting operations. These emissions should be carefully considered in the design and permitting phase. It is possible that emissions of either of these pollutants from a facility of the size outlined in this study, could trigger 'major source' status for PSD as they may be emitted in quantities of greater than 100 tons per year.

If emissions are of a magnitude that indicates a major new source is being constructed and PSD is triggered, the following elements must be included in the air permit application for each pollutant with a significant net emissions increase: A PSD review performed in accordance with EPA guidance involves six requirements:

1. Demonstration of the application of Best Available Control Technology
2. Demonstration of compliance with each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63
3. Air quality impact analysis (modeling)
4. Class I area impact analysis (modeling)
5. Projected growth analysis
6. Analysis of the effects on soils, vegetation, and visibility

The most significant of these requirements are addressed in more detail below.

3.1.3.1 Best Available Control Technology

PSD regulations and NSR guidelines specify emission control requirements for new sources of air pollution. Any proposed major source or major modification, subject to PSD regulations, must conduct an analysis to ensure that emission sources of regulated pollutants employ Best Available Control Technology (BACT). NSR defines BACT as:

> *"an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall the application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61"*

3.0 ENVIRONMENTAL PERMITTING

BACT is pollutant-specific and is determined on a case-by-case basis by taking into account the energy, environmental impacts, economic impacts, and other costs associated with each control technology. NSR guidelines specify a top-down process for determining BACT for each regulated pollutant. The top-down process includes the following steps:

- Identify all control technologies
- Eliminate technically infeasible options
- Rank remaining control technologies by control effectiveness (the discussion should include the percent pollutant removed, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts)
- Evaluate the most effective controls
- Select BACT

A BACT analysis would need to be conducted as part of a PSD permit application for all emission sources that emit pollutants for which the project triggers PSD review. This would include any fired combustion units (heaters, superheaters, auxiliary boilers, or thermal oxidizers), flares, process vents, cooling towers, and emergency generators, and solid material handling at the gasification plant.

3.1.3.2 Class I Area Impacts (Modeling)

U.S. EPA has designated certain areas of special national or regional value from a natural, scenic, recreational, or historic perspective as ‘Class I’ areas that are afforded special protection under the PSD regulations. The potential gasification site in western Kentucky is within 200 km from two Class 1 areas, Mammoth Cave National Park in Kentucky and Mingo National Wildlife Refuge in Missouri. The insert within Figure 3-1 illustrates the location of the potential gasification site to these sensitive Class 1 areas.

Applicants proposing new or modified major sources locating within this area need to consult with the Federal Land Managers (FLM), and will likely be required to submit emission impact modeling. This modeling could include Significant Impact modeling for SO_2, NO_x, CO, and PM_{10}/$PM_{2.5}$, as well as regional haze analyses, deposition analyses for sulfates and nitrates, and additional impact analyses for soils and vegetation. If the proposed facility is a ‘minor’ source of air pollution (less than 100 tons per year for all pollutants) for the New Source Review (NSR) regulations, this analysis would not be required.

3.1.3.3 Startup and Shutdown Emissions

Excess emissions during startup and shutdown events need to be considered in the facility PTE for determination of PSD applicability, and the ambient air quality analysis for major new sources. Most significantly, the flaring of sour syngas during startup could result in very high

3.0 ENVIRONMENTAL PERMITTING

short-term SO_2emission levels It is possible that high short-term mass emission rates of SO_2 will cause problems in the modeling of ground level impacts in comparison with federal ambient air quality standards (3-hr and 24-hr) described above for SO_2. In the Secure Energy (Decatur, IL) SNG plant permit, SO_2 emissions during startup and malfunction accounted for 90% of the total facility SO_2 emissions.

Design consideration should be given to efforts that can reduce the duration or magnitude of this flaring such as, starting up on low-sulfur feedstocks (e.g., methanol) to reduce the period of time that high sulfur syngas would be flared during startup. In addition, air dispersion modeling of the proposed startup flaring conducted early in the project development can help determine the extent of the potential impacts and guide the level of design mitigation needed.

3.1.3.4 CO_2 Vent Emissions

Even a plant intended to sequester all of the CO_2 will likely have some periods when this stream needs to be vented or flared to the atmosphere. While this stream is mostly CO_2, even small concentrations of CO, sulfur, and VOCs at the high flow rates of this stream can, depending upon plant operations, contribute to modestly high annual emissions rates. The amount of CO and VOCs that will ultimately be emitted will be directly related to the to the amount of venting anticipate in the permitting, and will need to be included in the annual PTE used to determine if the project is a major or minor new source for air permitting purposes.

3.1.4 Other Potential Air Permitting Issues

Some elements of the air permitting review process are somewhat subjective, such as what constitutes Best Available Control Technology and what level of Class I impacts are acceptable. Consequently, air permitting can involve lengthy negotiations with Kentucky DAQ, U.S. EPA, and FLMs. In addition, draft air permits are common targets of protests or lawsuits by groups opposed to such projects. Major coal-based projects permits, in particular, are routinely challenged, which can delay the permitting process and the start of construction.

Another area of potential future permitting complexity for coal-based projects involves greenhouse gas emissions. Greenhouse gases (i.e., CO_2, methane, etc.) are not currently regulated in Kentucky, as in some state programs, but there is a strong likelihood that these pollutants will be regulated at some point in the future by U.S. EPA.

In summary, air permitting for a large facility can be a complex and involved process. Consideration of total facility air emissions and related air permitting issues should commence very early in the design and planning of the proposed project to insure that proper time and resources are allocated address any potential issues.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Based on the scope of work described in URS' proposal to the Commonwealth of Kentucky, the following report describes in detail the anticipated permitting and regulatory procedures for siting and development of a coal gasification facility in western Kentucky. As previously discussed, the development and design of the proposed coal gasification facility that would in all likelihood include a coal mine, a natural gas pipeline, an electric transmission line, a carbon dioxide pipeline and underground storage reservoirs, a coal gasification plant, an enhanced oil recovery operation, and a landfill.

This report was based on written, telephone, and personal contacts with federal and state government agencies, review of published data and maps, and the experience of URS' professionals. The information in this analysis is based on responses received as of May 29, 2008.

4.1 APPROACH

To provide a permit and regulatory analysis to the Commonwealth of Kentucky, URS researched published materials, and contacted appropriate government agencies in order to discuss general development requirements and clarify specific permitting requirements. Because specific project locations have not yet been identified, potential local permitting requirements were not fully evaluated under this scope of work.

In addition to contacting the appropriate regulatory agencies, URS reviewed relevant federal, state, and select local regulations which, based on the information provided to URS, will likely be applicable to the proposed facility. URS has also provided general information regarding other areas that might require permits or agency contacts once a specific project location has been secured.

4.2 ASSUMPTIONS

This Permitting Analysis is based on preliminary conceptual parameters as communicated by the Commonwealth of Kentucky. As design details are not yet fully developed, the basis for the permit analysis is established on assumed facility requirements. These facilities are presented below. If assumptions regarding facility requirements are not correct, the corresponding permitting analyses may require modification. The following facilities are assumed to be required:

- Coal Gasification Combined Cycled Power Plant
- Coal Mine
- Natural Gas Pipeline
- Electric Transmission Line
- Carbon Dioxide Pipeline and Underground Storage Reservoirs

4.0 PERMITTING ANALYSIS KENTUCKY SITES

- Enhanced Oil Recovery System
- Landfill

For the purpose of this regulatory analysis it has been assumed that these proposed facilities are representative of those commonly associated with a new coal gasification facility. However, there are any number of complicating design and operational factors that could influence the types and number of regulations that may pertain to a specific project or to the time necessary to obtain those permits needed to construct and operate the facility. Examples of some of the factors that could influence permit types and timeline include:

- Existing facilities at or near the site could have their existing permits altered as a result of the proposed facility.
- Best available control technology is a moving target. BACT may vary between EPA districts; size, type, and configuration of proposed generating equipment; and recent commitments made by other sponsors of similar facilities. Local perceptions may also influence acceptable air emission rates.
- Site location could play a major role in determining the type and number of permits require. For example, a rural location is not necessarily an advantage as grassroots opposition could even be more organized in rural locales.
- Depending upon the location selected for the gasification facility ambient plant noise levels could play a major factor in the ability to easily permit the new facility.

4.3 ENVIRONMENTAL PERMITTING AND LICENSING

4.3.1 Hydrogeologic Permitting

4.3.1.1 Floodplain Construction Permit

Permit Description

A Floodplain Construction Permit is required prior to the construction, reconstruction, relocation, or improvement of any dam, bridge, culvert, placement of fill, residential and commercial buildings, or other obstruction across or along any stream or in the floodway of any stream. The Kentucky Division of Water - Floodplain Management Section has the primary responsibility for the approval or denial of proposed construction and other activities in the 100-year floodplain of all streams in the commonwealth. A permit is also required to deposit or cause to be deposited any matter that will in any way restrict or disturb the flow of water in the channel or in the floodway of any stream.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Regulatory Citation

KRS 151.250, 151.260, 151.280 151.310 and 401KAR 4:020 through 4:060

Governing Agency

KDEP Division of Water

Summary of Requirements

The process for obtaining a permit begins with the submittal of a completed application with a location map, plans of the proposed construction, and the addressing of public notice. If there is existing flood data regarding the proposed site location (i.e., National Flood Insurance Program flood maps, U.S. Army Corps of Engineers flood studies or previous permit data), then a permit review may begin. If there is no existing data, the submittal of survey information is required in order to perform an in-house flood study of the area. In addition, activities which result in physical disturbances to wetlands or streams may also require a Section 401 Water Quality Certification (WQC) Permit. The Section 401 WQC and Floodplain Construction Permit are submitted concurrently within the combined application that is reviewed by both the Division of Water - Floodplain Management Section and Water Quality Certification staff.

Floodplain Management Section engineers use the U.S. Army Corps of Engineers HEC-2 and HEC-RAS computer programs to analyze the effects of the proposed construction on existing flood conditions. Use of this program (or flood studies if they are available) enables the establishment of expected 100-year flood heights and the delineation of the floodway (a portion of the floodplain that is restricted to little or no construction). From this analysis, construction limits for fills and buildings and required elevations for finished floors or flood proofing can be provided. For all construction, especially bridges and culverts, a check is made to ensure that the project has only minimal impacts on existing flood levels. Regulations limit the effect of the new construction on flood levels to a maximum of one foot. If the proposed project is unacceptable based on the review, the applicant is sent a denial letter with possible options.

If the reviewer determines the project meets regulatory requirements and that all deficiencies have been corrected and all necessary modifications to the drawings have been made, a draft permit is written which will be reviewed by the supervisor and branch manager. If they concur that the proposal meets all state floodplain laws, regulations and standards, the permit is prepared and signed. Appropriate requirements and limitations are listed on the permit. The permit also bears the condition that construction must begin within one year of the date of signature. If started within that one-year period, the permit is valid until project completion. If objections to the project have been raised, letters to those objecting are also sent with instructions as to their rights for a hearing under the statutes.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

The application is submitted to:

Kentucky Department for Environmental Protection
Division of Water Floodplain Management Section
Water Quality Certification Section
14 Reilly Road
Frankfort, KY 40601
Tel: (502) 564-3410
Fax: (502) 564-4245

Schedule Considerations

- Applications are acted upon within 20 working days from the Division of Water's receipt of a complete application.
- If location of structures are within floodway and Hec-Raz modeling is required then review will begin with full completion of application. If Hec-Raz modeling is required then the review of the application will most likely extend beyond the initial 20 day period.
- Permit allows one year for construction to begin.

Potential Problem Areas

- None identified

4.3.1.2 Floodplain Development Permit

Permit Description

A Floodplain Development Permit may be required by a local agency (county/city) prior to the proposed construction and other activities in the 100-year floodplain of all streams within the municipal boundary area.

Regulatory Citation

Local Agency Regulation

Governing Agency

Local Agency - site dependant

Summary of Requirements

The state approved Floodplain Construction Permit can be submitted to the local agency for review to determine whether the project meets local regulatory requirements within the

4.0 PERMITTING ANALYSIS KENTUCKY SITES

floodplain. If the reviewer determines that state permit does not meet local standards, then the submittal of a Floodplain Development Permit application is required. However, if the reviewer determines the state permit meets local regulatory requirements, a Floodplain Construction Permit is not required.

4.3.1.3 Section 401 Water Quality Certification (WQC)

Permit Description

The Clean Water Act Section 401 Water Quality Certification (WQC) program in Kentucky ensures that activities involving a discharge into waters of the state and requiring a federal permit or license, are consistent with Kentucky's water quality standards in Title 401, Chapter 5, of the Kentucky Administrative Regulations.

The Section 401 WQC is tied directly to environmental permits issued by the U.S. Army Corps of Engineers related to potential physical impacts to streams and wetlands. Projects that involve the discharge of dredged or fill materials into waters of the United States, including wetlands, are regulated by the U.S. Army Corps of Engineers under the Clean Water Act Section 404 and require Section 401 WQC. Examples of activities that may require a Section 404 permit and Section 401 WQC include stream relocations, road crossings, stream bank protection, construction of boat ramps, placing fill, grading, dredging, ditching, mechanically clearing a wetland, building in a wetland, constructing a dam or dike, and stream diversions.

General Section 404 permits issued by the federal government authorizing discharges into waters of the United States, such as the U.S. Army Corps of Engineers' Nationwide Permits, require a water quality certification from the state. The state may certify, condition, or deny certification for the general permit. Projects authorized under general permits where certification is denied by the state, require a separate application to the state for water quality certification.

Activities that occur in a regulated floodplain may also require a Floodplain Construction Permit from the Kentucky Division of Water. The Section 401 WQC and Floodplain Construction Permit are submitted concurrently within the combined application that is reviewed by both the Division of Water - Floodplain Management Section and Water Quality Certification staff.

Regulatory Citation

Clean Water Act (CWA) Section 401, KRS 224.16-050, and 401 KAR Chapter 5

Governing Agency

KDEP Division of Water

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Summary of Requirements

A Section 401 WQC from the KDEP-Division of Water is required in conjunction with the Section 404 permit. If an Individual Section 404 permit is required, the U.S. Army Corps of Engineers Public Notice serves as the application for the Division of Water WQC. If an activity is covered under a U.S. Army Corps of Engineers Nationwide Permit, the applicant is required to submit the completed state application form along with a detailed description of the proposed action, location maps, detailed plans/drawings/specifications, and a copy of the U.S. Army Corps of Engineers letter to the applicant authorizing the activity under a nationwide permit.

The Section 401 WQC and Floodplain Construction Permit are submitted concurrently as a combined application. The WQC requires wetland delineation, mitigation design, construction, and subsequent monitoring.

Governing Agency

Kentucky Department for Environmental Protection
Division of Water
Floodplain Management Section
Water Quality Certification Section 14 Reilly Road
Frankfort, KY 40601
Tel: (502) 564-3410
Fax: (502) 564-4245

Schedule Considerations

- No time frame is set by regulation. Normal processing time is 60 days. More complex proposals require additional time for information gathering.

Potential Problem Areas

- Delay if application is incomplete.

4.3.1.4 Kentucky Pollutant Discharge Elimination System (KPDES) Permits

The Kentucky Pollutant Discharge Elimination System (KPDES) regulations require a permit for the discharge of pollutants from any point source into waters of the commonwealth. The KPDES regulations were promulgated to, and in accordance with Federal Water Pollution Control Act (Clean Water Act — Section 402) and the Kentucky Revised Statutes (KRS) Chapters 13A and 224.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Wastewater discharge from the proposed coal gasification facility is assumed to consist of: (1) process wastewater consisting of cooling tower blowdown from non-contact cooling, condensate from air chillers and wastewater from water deionization systems; (2) sanitary wastewater from restrooms, locker rooms, drinking fountains, etc.; and (3) stormwater generated from construction activities and from industrial/mining activities during operations. These are addressed in separate sections below.

KPDES Construction General Permit

A stormwater permit (KRS 224.16-050, 224.16-060, 401KAR 5:055 and 5:060) is required for construction activities that will disturb more than 5 acres (note-recent revisions to federal regulations under 40 CFR 122.26 has reduced this minimum disturbed area to 1 acre; this will be incorporated into state regulations in the near future). A KPDES Construction Storm Water Discharge General Permit is available from the Division of Water. A Notice of Intent (NOI) letter is submitted to request KPDES General Permit Coverage.

The KDEP has recently reported that the general storm water permits for Construction Activity (KYR10) and "Other" Industrial Activity (KYROO) expired on Sept. 30, 2007. If you are beginning a construction project, you are required to continue to submit the NOI as previously required. The KDEP Division of Water is currently drafting and reviewing the requirements for these facilities.

Permit Description

KPDES Construction Storm Water Discharge General Permit

Governing Agency

KDEP Division of Water

Summary of Requirements

Application for coverage under the general permit involves the following:

- A NOI letter is submitted to the Division of Water at least 48 hours prior to commencement of construction-related activities to request KPDES General Permit Coverage.
- A storm water pollution prevention plan (SWPPP) must be submitted with the NOI.

Schedule Considerations

For KPDES General Permit coverage, an NOI is required to be submitted to the KDEP Division of Water at least 48 hours prior to commencement of construction-related activities.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Permits are valid for five years. Submit complete application approximately 45 days prior to disturbance.

KPDES Individual Permit

Description

Discharge of pollutants from any point source to waters of the State of Kentucky requires a National Pollutant Discharge Elimination System (NPDES) permit administered by the KDEP Division of Water [Legal Authority: KRS 224.10-100, 224.16-050, 224.70-110, 224.70-120, 401 KAR 5:001, and 410 KAR 5:055-5:080]. Compliance with Kentucky Pollutant Discharge Elimination System (KPDES) Permit program requirements constitutes compliance with operational permit requirements of 401 KAR 5:005.

Regulatory Citation

Clean Water Act (CWA) Section 402

KRS 224.10-100, 224.16-050, 224.70-110, 224.70-120, 401 KAR 5:001, and 410 KAR 5:055-5:080

Governing Agency

KDEP Division of Water

Summary of Requirements

Application for an Individual Permit requires submission of KPDES Form 1 (General Information), Form C (Manufacturing Establishments and Mining Operations), and Form F (Storm Water Associated with Industrial Activity).

Whole Effluent Toxicity (WET) limits have been added to Kentucky Pollutant Discharge Elimination System (KPDES) permits in Kentucky since 1988. The WET limits and testing may be a parameter of the KPDES permit for the facility.

Forms are available at the KPDES Branch web site:

http://www.water.ky.gov/homepage_repository/kpdes_permit_aps.htm

or by phone at (502) 564-3410.

Schedule Considerations

Upon submittal, the application undergoes a 30-day administrative completeness review by KDEP Division of Water. KDEP notifies the applicant in writing whether the application is

4.0 PERMITTING ANALYSIS KENTUCKY SITES

considered complete or incomplete. Once a draft permit is prepared, at least 30 days are allowed for public comment. A public hearing is scheduled (with 30-day advance notice) if there is significant interest in the draft permit. The process typically requires at least 180 days. KDEP suggests that a meeting be held prior to beginning a new project. Facilities applying for an Individual Permit should submit appropriate application forms 180 days before commencing the industrial activity.

Potential Problem Areas

Significant public comments and public hearings could delay the permit approval process.

KPDES Wastewater Facility Construction Permit

According to the KDEP Division of Water, no additional permit would be required if the disposal of sanitary wastewater does not involve installation of new sewers or pump stations. However, approval for the discharge would be needed from the local Publicly Owned Treatment Works (POTW). Requirements vary by locality. If installation of sewers or pump stations is involved, a Wastewater Facility Construction Permit (coordinated with a KPDES permit) would be required in addition to POTW approval.

Permit Description

KDEP Division of Water Wastewater Facility Construction Permit. [Legal Authority: KRS 224.10-100, 224.16-050, 224.70-110, and 401 KAR5:005. Submitted concurrently with KPDES Permit application described previously.

Regulatory Citation

KRS 224.10-100, 224.16-050, 224.70-110, and 401

KAR5:005

Governing Agency

KDEP Division of Water

Summary of Requirements

The necessary information to be completed would include the KPDES Form 1 (General Information), Form C (Manufacturing Establishments and Mining Operations), Form F (Storm Water Associated with Industrial Activity) and Construction Permit Application Form W-1.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Schedule Considerations

The application for a Wastewater Facility Construction Permit is coordinated with the KPDES Permit. The complete application and required support materials should be submitted at least 180 days prior to the date the permit is desired. When construction is completed, applicant must submit registered engineer's certification that facility was constructed in accordance with approved plans. If construction is not begun within 12 months of permit issuance, a new permit or extension must be obtained.

Potential Problem Areas

- Requirement to obtain a KPDES Wastewater Facility Construction Permit in addition to approval of the POTW could cause delays.
- Local requirements and time frame for review may vary.

4.3.1.5 On-Site Sewage Disposal Permit (Septic System)

Permit Description

Disposal of sanitary wastewater via an on-site disposal system (i.e., septic tanks with leach fields or mounds that do not discharge to surface water) will require a permit issued by the Kentucky Department for Public Health, Environmental Management Branch or an authorized local board of health (902 KAR 10:085). KRS 211.370 allows a local board of health, which has been authorized by the Department for Public Health to serve as its agent, to adopt regulations relating to the proper operation and maintenance of onsite sewage disposal systems. Authorized local health departments conduct onsite evaluations to determine whether site and soil conditions are suitable for the installation of onsite wastewater systems. Certified inspectors perform site evaluations and inspections in Kentucky. Certified Installers are required to install systems in Kentucky except in some instances wherein an individual homeowner may obtain a homeowner's permit to install their own system. Septic systems may be prohibited within certain areas served by a POTW.

Regulatory Citation

902 KAR 10:085

Governing Agency

Kentucky Department for Public Health

Summary of Requirements

Contact local board of health (typically the county in which the site is located) for appropriate forms and procedures.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Additional information may be obtained from the Kentucky Department for Public Health Division of Public Health Protection & Safety web site at:

http://publichealth.state.ky.us/environm.htm or by contacting:

Kentucky Department for Public Health
Division of Public Health Protection
Environmental Management Branch
275 East Main Street,
Frankfort, KY 40621
Phone: (502) 564-4856
Fax: (502) 564-6533

Schedule Consideration

Local review time is not established by regulation. Check with local health department.

Potential Problem Areas

Poor soil conditions could require alternate designs. Should a design requiring a discharge to surface water be the only viable alternative, a KPDES permit would be required. A groundwater protection plan may also be required from the KDEP Division of Water.

4.3.1.6 Groundwater Protection Plan

Plan Description

A Groundwater Protection Plan (GPP) is required to be developed and implemented when any activity with the potential to contaminate groundwater is engaged in Commonwealth of Kentucky. A GPP identifies activities that could potentially contaminate groundwater at a facility and defines the best management practices (BMPs) used to protect groundwater.

Regulatory Citation

401 KAR 5:037 and KRS 224.01-010, 224.10-100, 224.070-100

Governing Agency

Kentucky Natural Resources and Environmental Protection Cabinet (KNEPC) and KDEP Division of Water — Groundwater Branch

Summary of Requirements

Generic plans are to be submitted to the Kentucky Natural Resources and Environmental Protection Cabinet (KNREPC) for approval before implementation. Site-specific plans are not required to be submitted until requested by KNREPC or KDEP Division of Water - Groundwater Branch. Plans must be available to the public.

Schedule Considerations

Plan must be developed before activity with potential to contaminate groundwater begins.

Potential Problem Areas

- None identified

4.3.1.7 Water Withdrawal Permit

Permit Description

In Kentucky, a Water Withdrawal Permit is required to withdraw, divert, or transfer public water from a stream, lake, groundwater source, or other body of water. The water withdrawal program governs all withdrawals of water greater than 10,000 gallons per day from any surface, spring, or groundwater source. Exceptions to the permit are for domestic purposes (needs for one household); agricultural withdrawals, (including irrigation), steam-powered electrical generating plants whose retail rates are regulated by the Kentucky Public Service Commission or for which facilities a certificate of environmental compatibility from such commission is required by law; or underground injection in conjunction with operations for the production of oil and gas.

Regulatory Citation

KRS Chapter 151

Governing Agency

KDEP Division of Water

Summary of Requirements

If facility is not exempt as a steam powered electric generating plant users whose rates are regulated by the Kentucky Public Service Commission, a Water Withdrawal Permit must be obtained. Applications for a Water Withdrawal Permit are obtained from the KDEP Division of Water. Standard permits require monthly reporting of actual withdrawals.

If a groundwater source is required, water well construction must comply with the requirements of 401 KAR 6:310 and 320.

Well logs are required to be submitted to the Kentucky Geological Survey.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Schedule Considerations

Permit approval or denial has a time limit of 90 days from submission of an administratively complete application.

4.3.1.8 Public Water System Construction and Operations Permits

Permit Description

It is assumed that potable water will be provided by a local public system, if available. If a public water system is not available, potable water is assumed to be provided by the onsite facilities. These systems would likely be non-transient, non-community water systems (NTNCWS), defined at 401 KAR 8:010 as systems for which 25 or more of the same individuals have access to water provided by the site for at least six months out of the year. As such, the facilities would require a public water supply approval from the KDEP Division of Water (KRS 224.10-110 and 401 KAR 8:100).

Facilities that do not regularly serve at least 25 of the same people over six months per year are defined as "transient non-community water systems." Water quality treatment and monitoring requirements for public water systems apply to transient non-community water systems. However, if less than 25 persons are served by the system in an average year and the system has less than 15 connections, it does not meet the definition of a public water supply. Such a system would be required to meet local Health Department requirements, but if withdrawals were less than 10,000 gallons per day, no state permit would be required.

Pursuant to KRS 224.10-110 and 401 KAR 8:100 approval to construct a Public Water Supply System is required prior to construction or installation of any new facilities in any public or semi-public water supply.

The applicant should contact the Division of Water and provide detailed engineering plans and specifications of the proposed water supply system. The waterline submittal checklist form (Form #DEP7102) should accompany the application submittal. The Division of Water will approve or disapprove the system.

Operational permits are issued by the Permits and Plans Review Section for water treatment systems that produce their own drinking water. The operational permits address sampling and analytical laboratory requirements, frequency of reporting, operator certification requirements and special conditions that may be required.

Regulatory Citation

KRS 224.10-110 and 401 KAR 8:100

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Governing Agency

KDEP Division of Water

Drinking Water Branch

Permits and Plans Review Section

Summary of Requirements

Preliminary engineering plans submitted by accredited engineers are reviewed for new or upgraded water treatment facilities. The waterline submittal checklist form (Form #DEP7102) should accompany the application submittal. The Division of Water will approve or disapprove the system.

If a new treatment plant is proposed or the source of raw water for an existing water system is to be changed, then water quality analyses are required.

Schedule Considerations

Time required for approval of a Public Water Supply System is approximately 45 days from submission of a complete permit application. If construction has not begun within one year of approval, the approval expires. The approval may be extended upon request to the Division of Water.

4.3.1.9 Spill Prevention, Control, and Countermeasure (SPCC) Plan

Permit Description

The Spill Prevention, Control, and Countermeasure (SPCC) rule includes requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires specific facilities to prepare, amend, and implement SPCC Plans. Before a facility is subject to the SPCC rule, it must meet three criteria: 1) it must be non-transportation-related; 2) it must have an aggregate aboveground storage capacity greater than 1,320 gallons or a completely buried storage capacity greater than 42,000 gallons; and 3) there must be a reasonable expectation of a discharge into or upon navigable waters of the United States or adjoining shorelines.

Regulatory Citation

40 CFR Parts 110 & 112, 401 KAR 5:090, and KRS 151.125

Governing Agency

U.S. Environmental Protection Agency

Summary of Requirements

Preparation of the SPCC Plan is the responsibility of the facility owner or operator, but it must be certified by a licensed professional engineer.

Although each SPCC Plan is unique to the facility, there are certain elements that must be included in order for the SPCC Plan to comply with the provisions of 40 CFR 112. Three areas which should be addressed in the Plan are: 1) operating procedures the facility implements to prevent oil spills; 2) control measures installed to prevent oil from entering navigable waters or adjoining shorelines; and 3) countermeasures to contain, cleanup, and mitigate the effects of an oil spill that has an impact on navigable waters or adjoining shorelines.

Schedule Considerations

A facility that is starting operation between August 12, 2002 and July 1, 2009, is required to prepare and implement a SPCC plan by no later than July 1, 2009. A facility that is starting operation after July 1, 2009, is required to prepare and implement a plan prior to beginning operation.

Potential Problem Areas

- None identified

4.4 ECOLOGICAL PERMITTING

4.4.1 Section 404 Clean Water Act Permit / Section 10 Rivers and Harbors Act Permit

Permit Description

A U.S. Army Corps of Engineers Permit is required for discharges of dredged or fill materials into the waters of the United States under Section 404 of the Clean Water Act and/or Section 10 of the Rivers and Harbors Act. This is facilitated using either individual permits or via use of nationwide (general) permits.

Under Section 404 of the Clean Water Act, the U.S. Army Corps of Engineers may issue general permits on a nationwide, regional, or statewide basis for particular categories of activities that, when conducted in waters of the U.S., are presumed to cause only minimal adverse environmental impacts. Landowners undertaking these activities are not required to obtain an individual permit. The U.S. Army Corps of Engineers has identified and periodically updates a list of categories of activity that merit such broad approval. General permits are issued by the U.S. Army Corps of Engineers and apply throughout the country. Some of these categories require simply notifying the U.S. Army Corps of Engineers prior to commencement of

4.0 PERMITTING ANALYSIS KENTUCKY SITES

the activity in a wetland, and some do not. The U.S. Army Corps of Engineers requires the submittal of Notice of Intent, to cross a river, stream, and/or wetland, with the application for a general permit.

An individual Section 404 permit is required for activities with significant wetland impact potential. Individual permit applications are evaluated on a case-by-case basis using the Section 404(b) (1) Guidelines.

Since some projects may involve federal action by the U.S. Army Corps of Engineers with the issuance of the 404 permits, compliance with the Endangered Species Act and the National Historical Preservation Act is required. This mandates consultations with the United States Fish and Wildlife Service (USFWS) and the State Historic Preservation Office (SHPO). Some projects may also be to be under the purview of the National Environmental Policy Act (NEPA). Compliance with NEPA requires consideration of environmental impacts associated with a broad range of alternatives. Section 404 Clean Water Permit applicants must also apply to the Kentucky Division of Water (KDOW) for a CWA Section 401 Water Quality Certification. Additional permits from the KDOW may be required if the project involves construction in a floodplain (Stream Construction Permit) or if it could disturb more than one acre of ground (General Storm Water Permit).

Lastly, if any of the streams are evaluated as historical navigable waterways, then a Section 10 Permit would apply regardless of crossing method. In this case, any crossing relative to the waterway would require a Section 10 permit.

Regulatory Citation

Section 404/401 of the Clean Water Act / Section 10 of the Rivers & Harbors Act

Governing Agency

U.S. Army Corps of Engineers

Four U.S. Army Corps of Engineers District Offices service the Commonwealth of Kentucky. These offices are listed below:

U.S. Army Corps of Engineers Huntington District Office
ATTN: Jim Richmond Chief
North Permits Section
502 Eighth Street
Huntington, WV 25701-2070
(304) 529-5210

4.0 PERMITTING ANALYSIS KENTUCKY SITES

U.S. Army Corps of Engineers Nashville District Office
ATTN: Wayne Huddleston
P.O. Box 1070
Nashville, TN 37202-1070
Tel: (615) 736-2342
Fax: (615) 736-2342

U.S. Army Corps of Engineers Louisville District
ATTN: Regulatory Branch
OP-F 600 Dr. Martin Luther King, Jr.
P.O. Box 59
Louisville, KY 40202-0059
Phone: (502) 582-6461

U.S. Army Corps of Engineers Memphis District
167 North Main
Memphis, TN 38103
(901) 544-3471

Summary of Requirements

- Prior to submitting a complete application, a Notice of Intent should be submitted describing the location and activities proposed.
- Submit a completed application form along with a description of the proposed action, location maps, and detailed plans/drawings/specifications.
- A Section 401 WQC from the KDEP-Division of Water is required in conjunction with the Section 404 permit.

Schedule Considerations

- Typically less than 60 days if covered by a Nationwide Permit
- 75 to 90 days review period for an individual permit. The application is processed concurrently with the U.S. Army Corps of Engineers, Clean Water Act Section 404 permit application.

Potential Problem Areas

- Delay if application is incomplete, which can stretch the 90-day review period.
- U.S. Army Corps of Engineers will specify clearance required in navigable waters.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

4.4.2 Threatened and Endangered Species Analysis

The Endangered Species Act - Section 7 requires federal agencies, in consultation with USFWS and/or National Oceanic and Atmospheric Administration (NOAA) Fisheries, to ensure that their actions do not jeopardize the continued existence of endangered or threatened species or result in the destruction or adverse modification of the critical habitat of these species. An ecological evaluation of proposed sites and utility corridors will be required as part of the Kentucky Public Service Commission (KPSC) application for a Certificate of Environmental Compatibility. If a KPSC certificate is not required, an ecological evaluation may be required for U.S. Army Corps of Engineers permitting.

Regulatory Citation

Endangered Species Act - Section 7

Governing Agency

Kentucky Public Service Commission

4.5 CULTURAL RESOURCES PERMITTING

4.5.1 Cultural Resource Survey

A cultural resources survey would likely be required its part of any U.S. Army Corps of Engineers permitting. This survey would first require a literature and map review for both known archaeological and historic resources and to determine areas previously surveyed. Then in coordination with the Kentucky Heritage Council, on site surveys may be required depending on the resources identified or the potential for additional resources to be discovered.

4.5.2 Section 106 Review

It is highly likely that the activities associated with the construction of a new coal gasification facility would incorporate federal funding, licensing, or permitting. Under such activities, a Section 106 of the National Historic Preservation Act (NHPA) review would be required in order to ascertain the effect of these activities on properties listed or determined eligible for listing in the National Register of Historic Places.

According to the Kentucky Heritage Council there are three goals of the Section 106 review process:

- To identify historic properties listed in or eligible for listing in the National Register of Historic Places through studies of archaeological sites and historic buildings;

4.0 PERMITTING ANALYSIS KENTUCKY SITES

- If historic properties are found, the Federal agency or designee in coordination with Kentucky Heritage Council then assesses what effect its undertaking will have on them. It will then make one of three determinations: no effect, no adverse effect, or adverse effect.
- To find ways to avoid, minimize, or mitigate any adverse effects on historically significant resources, resulting in a Memorandum of Agreements (MOA).

Governing Agency

Kentucky Heritage Council
300 Washington Street
Frankfort, Kentucky 40601
Phone (502) 564-7005
Fax (502) 564-5820
http://www.state.ky.us/agencies/khc/khchome.htm

4.6 KENTUCKY PUBLIC SERVICE COMMISSION

4.6.1 Certificate of Public Convenience and Necessity

Permit Description

The Kentucky Public Service Commission (KPSC) regulates intrastate rates and services of investor-owned electric, natural gas, telephone, water and sewage utilities, customer- owned electric and telephone cooperatives, water districts and associations, and certain aspects of gas pipelines. KPSC's jurisdiction includes issuance of Certificates of Public Convenience and Necessity before construction and operation of “Utility” facilities within the state of Kentucky. A Utility is defined by the Kentucky Revised Statutes (KRS) rules (KRS 278.010 (3) as "any person, except a city, who owns, controls or operates or manages any facility used or to be used for or in connection with the generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights heat, power or other uses." It is possible that a separate application would be required for each an electric generation unit, electric transmission line, and a natural gas pipeline.

Regulatory Citation

807 KAR, KRS 278

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Governing Agency

Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, Kentucky 40602-0615
Phone (502) 564-3940
Fax (502) 564-3460

Summary of Requirements

- Engineering details of proposed project
- Means of financing construction and operation and maintenance of proposed project
- Public notification in newspaper

Schedule Considerations

- A NOI needs to be filed 30 days before submittal of the application
- 120-day review period for application

Potential Problem Areas

- Delay if application is incomplete.

4.7 MINING PERMITING

4.7.1 Underground Mining Permit Application

To construct an underground coal mine in Kentucky an Underground Mining Permit must be obtained if the conditions of the Nationwide Permit 50 (U.S. Army Corps of Engineers) are not met. Additionally, if this permit is required a 401 WQC must also be applied for. The agency review of this permit may be up to a year in length.

Governing Agency

Kentucky Department of Natural Resources
Division of Mine Reclamation and Enforcement
2 Hudson Hollow Road
Frankfort, KY 40601
Phone (502) 564-2340
Fax (502) 564-5848

4.0 PERMITTING ANALYSIS KENTUCKY SITES

4.7.2 Underground Mining License Application

This license accompanies the Underground Mining permit for the operation of an existing. This license would include safety plans to operate and maintain the underground mine. The license must be renewed yearly.

Governing Agency

Kentucky Department of Natural Resources
Office of Mine Safety and Licensing
1025 Capital Center Drive
Frankfort, KY 40601
Phone (502) 573-0140
Fax (502) 573-0152

4.7.3 Additional Mining Permits

Depending on the final designs of the project, there may be additional mining permits required. Both the enhanced oil recovery system and the underground coal mine may require some of these different permits. These may include but are not limited to:

- Blasting License Application / Purchasing and Receiving Explosives Permit (KDNR - Office of Mine Safety and Licensing)
- Surface Disturbance Permit (KDNR - Division of Mine Permits)
- Underground Injection Control (UIC) Class II Well Permit (U.S. EPA Region 4 - Groundwater and UIC Section)
- Solid / Special Waste Landfill Permits (KDEP – Division of Waste Management)
- Use of Vacuum Permit (Kentucky Department of Mines & Minerals – Division of Oil and Gas Conservation)

4.8 FEDERAL ENERGY REGULATORY COMMISSION

4.8.1 Certificate of Environmental Compatibility and Public Need

If the siting and design of the final project requires gas or electricity to be transmitted between states then it is possible that a Certificate of Environmental Compatibility and Public Need would be required for construction. The application for a certificate would require wetland delineations, stream assessments, and threatened and endangered species habits surveys in addition to cultural resource surveys.

4.0 PERMITTING ANALYSIS KENTUCKY SITES

Governing Agency

Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Phone (202) 502-8145

4.9 CONCLUSIONS

Based on the information provided by the Commonwealth of Kentucky and assumptions made by URS concerning the nature of the proposed facilities, URS's contact with federal and Kentucky agencies, and review of appropriate regulations, it appears that general permitting requirements are achievable. However, URS recommends early contact with the relevant local agencies, once specific project sites are determined. In any case, early evaluation of water resources is recommended as areas that have suitable geology to provide the quantities of both surface and groundwater assumed to be required could be limited in certain areas of Kentucky.

5.0 CARBON DIOXIDE SEQUESTRATION

As described in the Kentucky Coal Gasification Feasibility Study, Part 1, ("the Part I Study") one of the unique benefits of coal gasification technology is that in the process of converting an abundant resource into other useful energy forms and chemicals, the carbon dioxide (CO_2) waste product can be captured in a concentrated stream making it amenable to sequestration in deep formations. Section 4.0 of the Part I Study provided a discussion of geologic features and industry experience that support sequestration as a safe, viable method for capturing greenhouse gas emissions. The study focused on sequestration possibilities within a 50-mile radius of a potential Henderson/Union County coal gasification plant. The conclusion of this initial study showed that for the projected 30-year life of the plant, an estimated 5.8 million tons per year of captured CO_2 could be sequestered. The methods of sequestration available within this area include:

- Enhanced oil recovery (EOR) in Illinois basin oil fields, which have been depleted through primary production and secondary water flood. This would be the preferred method of sequestration, since it would provide an economic benefit to the plant as well as to the oil producers. As identified in the Part I Study, a maximum of only 4% of the plant's CO_2 can be accommodated by EOR in the 50-mile radius. However, a gasification plant located in Kentucky could make this resource available to local oil producers if they desire to pursue this option. For this reason local EOR will be covered more fully below including estimated costs and benefits.

- Injection in deep saline aquifers in either Kentucky or Illinois appears to offer the maximum potential for sequestering the plant's full CO_2 volume for the 30-year life of the plant. Although this option does not provide additional revenue for the gasification project it could help assure potential regulators that the proposed gasification facility is being constructed and operated in an environmentally friendly manner. In the Feasibility Study, Part 1, Table 4-5 identified the potential for sequestering over 1,000 million tons of CO_2 within the 50-mile radius surrounding the plant site. This was based on preliminary screening research done by the Midwest Geologic Sequestration Consortium. This research continues to further define the risks involved and to identify the depth and properties of the proposed geologic zones. For example, possible disposal zones range from a few thousand feet in the Knox Formation to more than 10,000 feet in the Mt. Simon Formation. The Kentucky Consortium for Carbon Sequestration is currently developing plans for drilling a test well in western Kentucky to further research the sequestration potential in this area. A similar test well is also planned in eastern Kentucky.

5.0 CARBON DIOXIDE SEQUESTRATION

- Since there appears to be a reasonable likelihood that a significant amount of sequestration capacity can be provided by deep saline aquifer injection within the search area, this report includes a conceptual design and estimated cost for a pipeline to transport CO_2 volumes, which are not used for local EOR, into the Illinois Basin for disposal. Until geologic zones and their characteristics are better defined through additional research, accurate estimates for drilling and equipping the required number of disposal wells cannot at this time be ascertained. The individual cost for a Knox Formation disposal well that meets yet undetermined Environmental Protection Agency design specifications could be in the range of $1.5 to $2.5 million, while a 10,000-foot Mt. Simon Formation well could be in the range of $3 to 5 million. The more significant unknowns at this time is the number of wells that will be required at a disposal site to provide the required daily injection rate to meet the plant's CO_2 output rate, and the well spacing required to provide the needed long term storage capacity. In addition, monitoring requirements such as pre-drilling and post injection seismic to keep track of the CO_2 plume in the formation have not yet been formulated.
- Non-mineable coal seam injection and organic shale injection with enhanced methane production also show promise as potential CO_2 sequestration methods. Each relies on the porous nature of the host rock to accept the injected CO_2 Subsequent displacement of naturally occurring methane found within the rock may ultimately result in its commercial production and sale. The search area theoretically exhibits potential for sequestering a portion of a gasification plant's CO_2 output in either of these geologic receptors. The Kentucky Consortium for Carbon Sequestration is currently developing plans for incorporating these storage options into its test well drilling program. These two options will not be discussed further in this report because it is too early in their research to make definitive analyses.

One additional and very significant option for sequestration of CO_2 would occur outside the original search area and has been proven to be technically and economically viable. This option involves the construction of a pipeline to transport the CO_2 to a basin with enough available stranded hydrocarbon reserves sufficient to accept the plant's full CO_2 output for use in EOR operations. A review of EOR operations across the US resulted in the study team touring Denbury Resources' Tinsley EOR operation in Mississippi. Viewing Denbury's very successful application of EOR technology reinforced a decision to perform a conceptual design and cost estimate for this option. This will be discussed in more detail later in this section of the report.

5.0 CARBON DIOXIDE SEQUESTRATION

5.1 WESTERN KENTUCKY CO_2 EOR

Section 4.0 of the Part I Study reviewed the broad aspects of geologic sequestration of carbon dioxide (CO_2) in hydrocarbon reservoirs within an approximate 50-mile radius of the proposed plant site area.

The coverage in Section 4.0 included a review of carbon dioxide properties, technical support for geologic sequestration based on oil and natural gas storage industry experience, generalized geology of the search area, and a preliminary screening of sequestration capacity in depleted oil fields, non-mined coal seams and saline aquifers.

Conclusions reached in Section 4.0 indicated that depleted oil fields located within the aforementioned 50-mile radius were capable of handling only a relatively small fraction of the total sequestration capacity needed to support the coal gasification plant, even if all available reservoir capacity were utilized. Additionally, the relatively shallow and geologically discontinuous nature of oil reservoirs in the search area predicted a relatively low incremental oil recovery factor from carbon dioxide injection and sequestration compared to other areas of the country. Recognizing these deficiencies, the potential remains for economically-attractive enhanced oil recovery from carbon dioxide injection if projects can be affordably constructed and operated.

This section of the report focuses on those individual reservoir engineering and geological characteristics of western Kentucky oil reservoirs which must be understood in order to develop a representative model, conceptual design and operation of a CO_2 enhanced oil recovery / sequestration project.

Western Kentucky Oil Reservoir Characterization

As described in Section 4.0 of the Part I Study, western Kentucky lies within the southern portion of the Illinois geologic basin, which has been an oil producing region for over a century. Oil production has been recorded from many of the geologic formations within the basin, with approximately 70% of the productive acreage in Illinois and approximately 67% of the productive acreage in Kentucky being within Mississippian-age formations.[1,2]. Mississippian-age formation geology and reservoir producing characteristics within the basin, are generally consistent and predictable. For these reasons, the focus of reservoir characterization will be on Mississippian-age formations and reservoirs due to their greater regional availability and overall potential for enhanced oil recovery.

The Mississippian geologic time interval (approximately 408 to 360 million years before present) was a period when large amounts of material that became sandstone, silts, shale, and limestone were deposited in the Illinois Basin. Original water contained in the pores of these rocks was later expelled by hydrocarbons as they migrated from source beds and became crude oil deposits. Table 5-1 is a compilation of Mississippian-age formation zones that contain oil reservoirs in western Kentucky.

Table 5-1 Productive Zones in Western Kentucky

Productive Zones in Western Kentucky
Clore Formation
Palestine Sandstone
Menard Formation (Chapman)
Waltersburg Sandstone (Fuqua sand)
Vienna Limestone
Tar Springs Sandstone (Jett sand)
Glen Dean Limestone
Hardinsburg Sandstone
Haney Limestone
Big Clifty Sandstone (Jackson sand)
Cypress Sandstone (Barlow sand)
Reelsville Limestone (Upper Paint Creek Limestone)
Sample Sandstone (Paint Creek sand)
Beaver Bend Limestone (Lower Paint Creek Limestone)
Bethel Sandstone (Benoist)
Renault Limestone
Aux Vases Formation
Ste. Genevieve Limestone (O'Hara, Rosiclare, McClosky)
St. Louis Limestone
Salem Limestone
Warsaw Limestone
Fort Payne Formation
Source: Kentucky Geological Survey

A literature search was conducted to characterize the geologic and reservoir engineering aspects of oil reservoirs within the productive Mississippian formations. The Illinois Geological Survey has conducted research into several Illinois Basin oil fields, at the individual reservoir level, under grants from the U.S. Department of Energy and the State of Illinois and published the results in a series of Illinois Petroleum (IP) reports.[3,4,5,6,7,8] The reports contain detailed geological mapping, rock descriptions, production histories and fluid analyses for Mississippian-age reservoirs in the state of Illinois. The IP reports were valuable in gaining a basic level of understanding of those characteristics that are at least analogous to, and in many cases directly correlative with western Kentucky reservoirs of similar age.

Table 5-2 is a summary of the key parameters that are considered useful for this feasibility study. A total of five oil fields were studied, containing 24 separate and distinct oil reservoirs. While there is a wide variability in some of the data from field to field, the overall characterization gained from the IP reports is that the individual Mississippian reservoirs tend to be moderately sized in terms of acre-feet of oil pay, and have generally responded within expectations to secondary water flood oil recovery augmentation.

Table 5-2 Comparative Illinois Oil Field Performance

Comparative Illinois Oil Field Performance						
I. Historical Information						
Field Name	Bartelso	Tamaroa	Richview	Stewardson	Zeigler	**Averages**
County, State	Clinton, IL	Perry, IL	Washington, IL	Shelby, IL	Franklin, IL	
Formation Name	Cypress	Cypress	Cypress	Aux Vases	Aux Vases	
Number of Reservoirs	5	7	3	5	4	
Minimum Depth, ft.	970	1,095	1,480	1,940	2,600	**1,617**
Porosity, percent	20	20	19	13	21	**19**
Average Reservoir Thickness, ft.	3.2	4.2	7.0	8.5	14.5	**7.5**
Average Reservoir Area, acres	355	153	63	213	84	**173**
Average Reservoir Acre-feet of Pay	1,064	643	441	1,813	1,170	**1,026**
Total Field Acre-feet of Pay	5,318	4,505	1,324	9,067	4,683	**4,979**
Water Saturation, percent	30	40	40	30	40	**36**
Residual Oil Saturation, percent	23.2	28.5	n/a	n/a	n/a	**26**
Oil Gravity, degrees API	36	29	38	36	38	**35**
Well Spacing, acres	10	10	10	10	10	**10**
Original Oil in Place, Stock Tank bbls	5,062,000	3,223,000	7,011,000	5,651,809	4,286,060	
Primary Oil Production, S.T. bbls	1,250,000	n/a	1,234,000	199,362	n/a	
Secondary Oil Production, S.T. bbls	1,250,000	n/a	2,011,000	748,937	n/a	
Total Oil Production, S.T. bbls	2,500,000	783,000	3,245,000	948,300	2,095,547	
Maximum Production Rate, bopd	550	360	1,095	170	800	
Average Production Rate, bopd	140	60	185	50	213	
II. Comparitive Analysis						
OOIP/ac-ft..	952	715	830	623	915	**807**
Total Production/ac-ft.	470	174	384	105	447	**316**
Maximum Production Rate/ac-ft.	0.103	0.080	0.130	0.019	0.171	**0.101**
Average Production Rate/ac-ft.	0.026	0.013	0.022	0.006	0.046	**0.023**
Data Source	IP 137	IP 138	IP 155	IP 139	IP 146, 153	

The average reservoir pay volume of 1,026 acre-feet indicated from the data in Table 5-2 provides some insight into the scope of operation that might apply to CO_2 enhanced recovery operations in western Kentucky. Even though oil fields may encompass many hundreds or thousands of acres, the oil fields are composed of many, relatively small and distinct reservoirs that must be treated as individual projects.

Because oil wells often penetrated multiple, vertically-stacked reservoirs, oil production was often commingled and not separately accounted for by reservoir. This makes individual reservoir performance analysis difficult, however in the whole, the Mississippian oil fields analyzed for Table 5-2 were capable of producing 316 stock tank barrels of oil per acre-foot, or approximately 39% of the original stock tank oil in place under a combination of primary and

5.0 CARBON DIOXIDE SEQUESTRATION

secondary water flood recovery mechanisms. Since not all of the reservoirs analyzed underwent secondary recovery, this level of performance is encouraging in spite of the relatively small reservoir areas.

Although published in-depth reports of analyses of individual Kentucky reservoirs, which exhibit characteristics similar to those reservoirs to those reservoirs studied in the Illinois IP series, were not located for western Kentucky oil fields, the Kentucky Geological Survey provided a copy of a proprietary report of leasehold performance, covering several reservoirs within the Poole Consolidated Field located in Henderson and Webster Counties.[9] Table 5-3 summarizes key parameters for eleven of the Mississippian-age reservoirs analyzed in the report.

Table 5-3 Leasehold Analysis within Poole CONS Field

Leasehold Analysis within Poole CONS Field					
Formation Name	**Number of Reservoirs**	**Average Acre-ft.**	**Average OOIP/ac-ft. S.T. bbls**	**Ave. 1963 Recovery/ac-ft. S.T. bbls**	**Ave. Ultimate Recovery/ac-ft. S.T. bbls**
Waltersburg	7	453	946	363	416
Tar Springs	4	939	836	194	324
Totals	11	630	902	291	378
Source: footnote 4					

The indicated average reservoir volume of 630 acre-feet is again relatively small. The range of average reservoir sizes from the Illinois and Poole Field data sets is approximately 450 to 1,800 acre-feet, with a combined average of approximately 900 acre-feet. With an average reservoir net thickness of 7.5 feet based on the Illinois data, the average reservoir area would be approximately 120 acres.

The indicated oil recovery for the Poole Field reservoirs as of 1963 was 291 stock tank barrels per acre-foot, or 32% of the original stock tank oil in place per acre-foot. The ultimate estimated recovery is 378 stock tank barrels per acre-foot, or 42%. This range fits with the Illinois average of 39 %, which generally reflects production into the 1990's. The Poole report indicates that an accepted average primary recovery for Illinois Basin reservoirs is approximately 16% of original oil in place under typical solution gas drive recovery conditions. This would indicate that water flooding provides an additional 23% to 26% oil recovery based on the Illinois and Poole data.

The total of 35 typical reservoirs examined is admittedly small compared to the total number of reservoirs within the search area. However, the key characteristics and reservoir oil recoveries appear to be reasonably consistent, therefore the sample reservoir population examined, in all likelihood, exhibits characteristics that are attributable to the total existing Mississippian-age formations found in the general area. The next step in the characterization process is to compare correlative data from the Illinois IP and Poole leasehold studies to the field-level information provided in the Kentucky Geological Survey database of fields selected for potential

5.0 CARBON DIOXIDE SEQUESTRATION

CO_2 enhanced oil recovery, known as the Kentucky Tertiary Oil Recovery Information System (TORIS) database. Table 5-4 summarizes the key field-wide parameters of Mississippian formations within the nine Kentucky TORIS fields located in western Kentucky, which are also the same nine fields described in the Part 1 Report.

It may be helpful to review the terminology utilized to describe oil properties as it relates to the Kentucky TORIS data. As discussed in the Part 1 Report, "oil field" is a term utilized to describe an assembly of many individual reservoirs located in a general geographic area. The individual reservoirs may be related geologically such as all being located atop a large regional geologic feature, or the relationship may simply be for geographic convenience. Several oil fields may be agglomerated together into a "consolidated oil field" for geographic or regulatory convenience or because again, some regional geologic feature makes such an agglomeration technically logical. In all cases, the individual reservoirs contained within the oil field or consolidated oil field, are mechanically separate and distinct from each other. Many of the fields presented in Table 5-4 are the large, consolidated oil fields.

Table 5-4 Comparative Western Kentucky (TORIS) Oil Field Performance

Comparative Western Kentucky (TORIS) Oil Field Performance										
I. Historical Information Field Name	**Apex**	**Birk City**	**Dixie**	**Hitesville**	**Morganfield**	**Poole**	**Smith Mills**	**Taffy**	**Uniontown**	**Averages**
County	Muhlenberg	Daviess, Henderson	Henderson, Union, Webster	Henderson, Union	Union	Henderson, Webster	Henderson, Union	Ohio	Union	
Discovery Year	1954	1938	1945	1943	1943	1943	1942	1926	1942	**1942**
Depth, ft.	825	1,679	2,028	2,405	2,198	2,622	2,488	625	2,011	**1,875**
Porosity, percent	18	16	18	14	16	16	17	21	18	**17**
Total Field Acre-feet of Pay, ac-ft.	180,555	87,900	26,340	73,850	51,466	204,996	49,784	49,400	71,640	**88,437**
Water Saturation, percent	67	34	36	52	38	66	66	35	32	**47**
Residual Oil Saturation, percent	20	27	36	23	41	15	28	44	43	**31**
Oil Gravity, degrees API	33	35	36	37	35	36	35	34	36	**35**
Oil Viscosity, cp	4.3	n/a	n/a	n/a	6.0	8.1	n/a	9.5	4.5	**6.5**
Formation Volume Factor, bbl/S.T.bbl	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	**1.05**
Well Spacing, acres	11.7	16.0	11.0	32.0	13.7	26.1	16.0	3.1	13.8	**16.0**
Original Oil in Place, Stock Tank bbls	66,100,000	40,900,000	17,900,000	35,400,000	40,400,000	74,600,000	42,600,000	49,800,000	62,600,000	
Primary Oil Production, S.T. bbls	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Secondary Oil Production, S.T. bbls	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Total Oil Production, S.T. bbls	22,100,000	13,200,000	6,000,000	18,100,000	12,600,000	34,200,000	19,500,000	14,400,000	20,400,000	
Average Production Rate, bopd	1,510	630	335	950	677	1,800	1,010	570	1,050	
II. Comparitive Analysis										
OOIP/ac-ft..	366	465	680	479	785	364	856	1,008	874	**653**
Total Production/ac-ft.	122	150	228	245	245	167	391	291	285	**236**
Maximum Production Rate/ac-ft.	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Average Production Rate/ac-ft.	0.008	0.007	0.013	0.013	0.013	0.009	0.020	0.012	0.015	**0.012**
Data Sources: Kentucky TORIS (KGS), Index to Oil and Gas Fields of Kentucky (KGS)										

Although individual reservoir data is not reported in the Kentucky TORIS data base, the key average values derived from the field-wide data is relevant to the characterization effort. The indicated oil recovery of 236 stock tank barrels per acre-foot, or approximately 36% of the 653 stock tank barrels per acre-foot of original oil in place in Table 5-4, compares reasonably well with the 39% from Table 5-2 and 32% to 42% in Table 5-3. There are, however, significant difference in the amount of original stock-tank oil in place per acre-foot among the three tables [807 (Table 5-2), 902 (Table 5-3), 653 (Table 5-4)]. Closer examination indicates that the higher water saturations reported in the Kentucky TORIS data base is the principal reason for the lower oil content. Recognizing that the Kentucky TORIS database encompasses the universe of

5.0 CARBON DIOXIDE SEQUESTRATION

Mississippian formations and reservoirs, including many that are not analyzed in Tables 5-2 or 5-3, it should theoretically be most reflective of the average to be expected in a "typical" field model of a western Kentucky oil reservoir.

Typical Western Kentucky Oil Reservoir

The information provided in Tables 5-2, 5-3, and 5-4 which, in general is representative of characteristics exhibited by Mississippian reservoirs in Illinois, within a small area of the Poole Consolidated Field, and for the major western Kentucky oil fields, respectively, have been incorporated and rationalized in developing characteristics of a typical western Kentucky Mississippian reservoir for purposes of modeling CO_2 injection and enhanced oil recovery operation. The resultant characteristics are presented in Table 5-5, followed by a discussion of the rationale for the value assigned for each characteristic.

Table 5-5 Typical Western Kentucky Oil Reservoir

Typical Western Kentucky Oil Reservoir	
Characteristic	**Value**
Reservoir	Mississipian
Discovery Year	1942
Depth	1,875 feet
Thickness	7.5 feet
Porosity	17 percent
Pressure	840 psia
Temperature	84° F
Initial Water Saturation	47 percent
Residual Oil Saturation	30 percent
Oil Gravity	35° API
Acre-feet of Oil Pay	1,000 acre-feet
Acreage	133 acres
Well Spacing	16 acres
Primary Recovery Method	Solution Gas Drive
Secondary Recovery Method	Water Flood
Number of Oil Wells	8 wells
Number of Injection Wells	3 wells
Original Oil in Place	700 bbls/acre-foot
Oil Recovery to date	250 bbls/acre-foot
Historical Ave.Production Rate	0.015 bopd/acre-foot
Maximum Production Rate	0.060 bopd/acre-foot

5.0 CARBON DIOXIDE SEQUESTRATION

Rationalization:

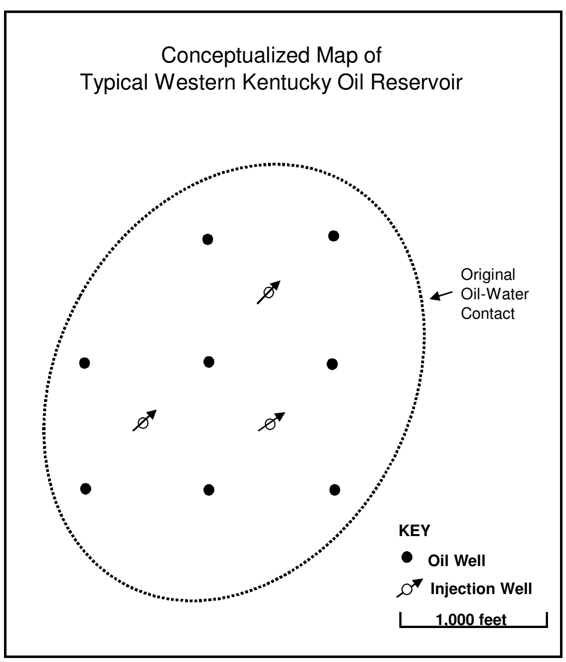
- Reservoir - Mississippian reservoir within any of the formations listed in Table 5-1.
- Discovery Year - The average discovery year for major western Kentucky oil fields; Table 5-4.
- Depth - Average depth of productive formations in major western Kentucky oil fields; Table 5-4.
- Thickness - Average thickness reported for the 24 Illinois reservoirs described in Table 5-2.
- Porosity - Average porosity reported for productive formations in major western Kentucky oil fields; Table 5-4.
- Pressure - Initial reservoir pressure at average depth based on a geo-pressure gradient of 0.44 psi per foot of depth.
- Temperature - Reservoir temperature based on a geothermal gradient of 65°F+1 degree per 100 feet of depth.
- Initial Water Saturation - Average reported for productive formations in major western Kentucky oil fields; Table 5-4.
- Residual Oil Saturation - Average of all values reported on Tables 5-2 and 5-4.
- Oil Gravity - Reflects consistent agreement of data on Tables 5-2 and 5-4.
- Acre-feet of Oil Pay - A value that lies within the range of values reported on Tables 5-2, 5-3 and 5-4, and recognizing the economics of scale for selecting a reservoir unit size in the upper half of the range for conceptual enhanced recovery operation. Similar results can be obtained from combining two reservoirs that are half this size.
- Acreage - Obtained by dividing the value for Acre-feet of Oil Pay by the value for Thickness.
- Well Spacing - Average well spacing reported for major western Kentucky oil fields; Table 5-4.
- Primary Recovery Method - Reflects the most common reservoir drive mechanism for western Kentucky oil reservoirs.
- Secondary Recovery Mechanism - Assumes the typical reservoir was water flooded, as is generally the case with most successful western Kentucky oil reservoirs.
- Number of Oil Wells - Obtained by dividing the value for reservoir acreage by the value for well spacing.
- Number of Injection Wells - Based on a typical 5-spot injection pattern, which is often utilized in water flooding operations.
- Original Oil in Place - A value that lies within the range of values reported on Tables 5-2, 5-3, and 5-4, and honoring the primarily average value reported for major western Kentucky oil fields; Table 5-4, which reflects the greatest diversity of productive Mississippian reservoir formations.

5.0 CARBON DIOXIDE SEQUESTRATION

- Oil Recovery to Date - Reflects a recovery factor of approximately 36%, consistent with the performance of major western Kentucky oil fields; Table 5-4.
- Historical Average Production Rate - Obtained by dividing the historic oil production by the number of years from discovery to the effective date of cumulative oil production. The value utilized lies within the range of values in Tables 5-2 and 5-4, honoring the apparent reduced performance of major western Kentucky oil fields; Table 5-4.
- Maximum Production Rate - Based on reported Illinois production rate versus time plots for reservoirs in Table 5-2, where the maximum annual production was approximately four times the historic average production annual rate.

A map representation of the conceptualized typical western Kentucky reservoir is provided in Figure 5-1. The ovoid shape of the reservoir structure is a simplified presentation of natural reservoir structures in the Illinois Basin, which commonly have a semi-ovoid or crescent shape in plane view. The eight oil wells are located on a uniform 16-acre spacing pattern, which is an over-simplification of actual well placements, which can often be somewhat scattered. The three water flood injection wells are placed in a 5-spot pattern where possible, which is commonly, but not uniformly utilized throughout the Illinois Basin. In fact, some operators use off-structure edge injection profiles, which have proven successful in many reservoirs. For purposes of the CO_2 modeling exercise, which will require utilization of the water injection wells, they are shown as being on structure. The map has been drawn to scale, with the area within the original oil-water contact incorporating as closely as possible 133 acres. Assuming an average reservoir net thickness of 7.5 feet, the reservoir productive rock volume is 1,000 acre-feet.

Figure 5-1 Conceptualized Map of Typical Western Kentucky Oil Reservoir



5.0 CARBON DIOXIDE SEQUESTRATION

Reservoir Fluid Properties

In its native discovery state, the typical western Kentucky reservoir contained crude oil that was entrained with natural gas. It was the natural gas in the oil that provided the pressure and driving force for oil to flow to producing wells for recovery. The natural gas swelled the otherwise viscous crude oil, making it "spongy" and easier to flow through the microscopic pore channels of the reservoir formation rock. The volume of natural gas initially entrained in the oil was finite, and eventually was nearly depleted after a number of years of this primary, solution-gas driven, production. The result was a significant decline in daily oil production over time due largely to the loss of driving pressure provided by the entrained gas and the subsequent reduction in the relative mobility of the oil compared to gas. At some point in the production history of the reservoir, a decision was made to inject water into specially-drilled injection wells to provide an artificial hydraulic driving force to enhance the declining oil production. Even though the reservoir oil had increased somewhat in viscosity due to the loss of its original gas, the typical western Kentucky reservoir responded quite well to water flooding as a secondary recovery technique due to favorable mobility ratio characteristics between the water and oil, and generally favorable characteristics of the reservoir rocks. The amount of crude oil that can be moved by water flooding is finite, and eventually the oil viscosity, relative permeability characteristics of the reservoir rock and capillary effects of the rock pore spaces have been reduced to the point that the economic benefit of water flooding is minimal as the resulting production from the wells is essentially large volumes of water commingled with only minor amounts of oil. It is at this stage that the investigation into the benefits of CO_2 injection begins.

At the typical western Kentucky reservoir depth, operating pressure and temperature, which are below the critical point for CO_2 as discussed in the Part I Study, injection of CO_2 into the reservoir will re-saturate and swell the viscous oil to some extent, lowering the viscosity and at the same time providing again a gas driving force to help increase production of some of the oil remaining in the reservoir rock pore spaces. By definition, the process is considered immiscible gas injection, and technically is a secondary recovery operation like water flooding. Initially, the CO_2 will also serve as a driving force to remove much of the flood water that currently also resides in the reservoir.

The extent to which CO_2 can appreciably recover incremental oil depends partially on the chemical and physical properties of the viscous oil remaining in the reservoir, and how these properties allow the oil to respond to gas re-saturation. In the absence of published laboratory results for western Kentucky Mississipian-age reservoirs, research which has been published on Illinois Basin crude oils in Mississippian-age reservoirs by the Illinois Geological Survey should be applicable to typical western Kentucky reservoir oils[10]. One of the Illinois reservoir oils analyzed was from the Dale Consolidated Field, which was included within the search area of the Part I Study.

5.0 CARBON DIOXIDE SEQUESTRATION

Of interest for this feasibility study are the swelling and viscosity reduction that will occur and the subsequent producing gas-oil-ratio that should be expected under a CO_2 enhanced oil recovery program. The degree of viscosity reduction should provide encouragement in that it appears that immiscible gas injection can be effective at this late stage in reservoir depletion for mobilizing some remaining oil fraction. The producing gas-oil-ratio will be important for designing and sizing surface equipment to capture and re-inject the CO_2 that is produced with the oil.

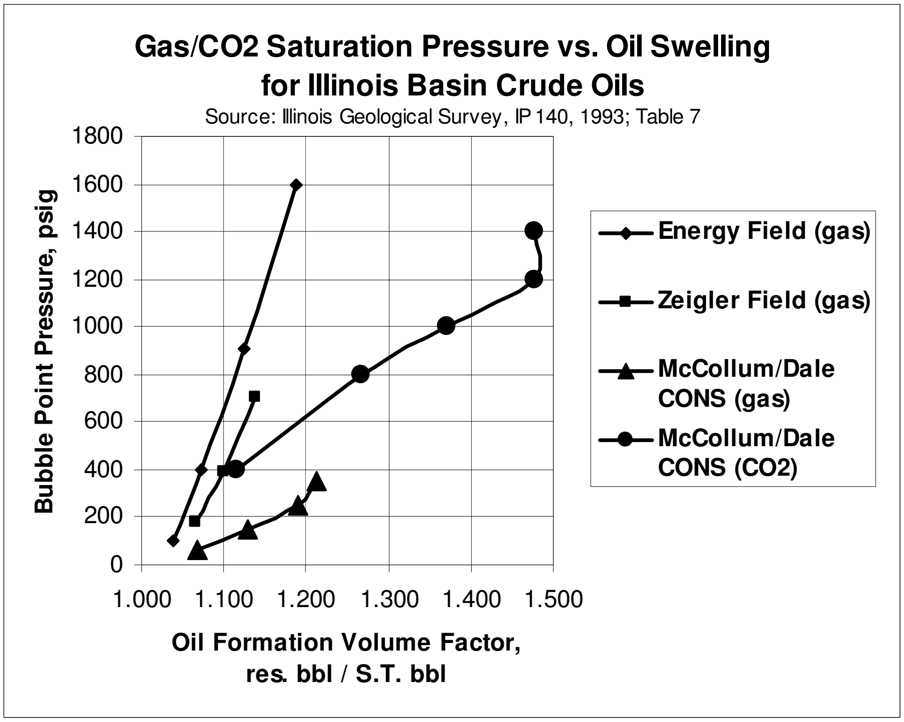
The crude oil research conducted by the Illinois Geological Survey[11] analyzed oil and natural gas samples from Mississippian-age reservoirs in the Energy Field, Zeigler Field and the McCollum Unit of the Dale Consolidated Field. These reservoirs are deeper than the typical western Kentucky reservoir, and therefore originally had higher initial pressure and temperature. However, the general oil and gas properties are considered sufficiently typical of Illinois Basin reservoirs that the trends observed in the laboratory study are applicable to the western Kentucky example.

The gas and oil samples were subjected to a wide range of pressure-volume-temperature (PVT) analyses to measure various properties and to compare measured results with standard industry correlation methods. Of primary interest to the research team was the impact of the high relative percentage of non-hydrocarbon fraction (carbon dioxide and nitrogen) that commonly is contained in Illinois Basin hydrocarbons, which makes use of standard correlation techniques problematic. Although not directly a concern of this feasibility study, some interesting observations related to this are discussed later.

Samples of natural gas and stock tank oil from each reservoir were recombined under various pressure and temperature conditions in the laboratory to measure the swelling tendencies of the crude oils. Figure 5-2 is a plot of some of the results, showing the relationship between bubble point pressure and the oil formation volume factor, which is a measure of the relative volume of a reservoir barrel of oil (gas enriched) to a barrel of the same oil at atmospheric stock-tank pressure conditions (gas depleted).

5.0 CARBON DIOXIDE SEQUESTRATION

Figure 5-2 Gas/CO_2 Saturation Pressure vs. Oil Swelling for Illinois Basin Crude Oils

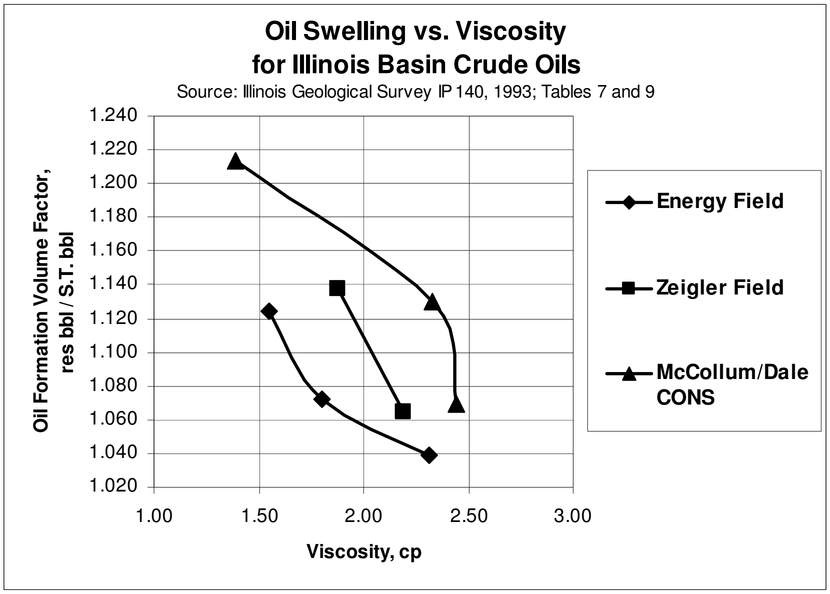


The Energy Field and Zeigler Field samples exhibit less swelling than the McCollum/Dale CONS sample when saturated with their native natural gas. This is largely due of the relatively high (9 to 15%) nitrogen content of the first two reservoir gases, as opposed to the McCollum sample (1% nitrogen), as well as a relatively high fraction of propane and butane in the McCollum gas. Nitrogen provides very low oil swelling due to its relatively large molecular size, and is therefore not considered an attractive gas for enhanced oil recovery. It can be seen that a McCollum oil sample subjected to CO_2 re-saturation exhibited substantial swelling. The conclusion that can be reached from Figure 5-2 is that the typical western Kentucky reservoir oil, at the modeled reservoir pressure of 840 psig, should exhibit swelling tendencies with CO_2 somewhere between the extremes shown on Figure 5-2, and at least as favorable as would be expected from re-saturation with its original native natural gas. If the native gas contained relatively high nitrogen content, the CO_2 could exceed the native swelling characteristics.

The relationship between oil swelling with natural gas and crude oil viscosity was examined by the research team, and the results are plotted in Figure 5-3. The general trend of the three reservoir oils is toward a reduction in viscosity with increasing swelling, as would be expected.

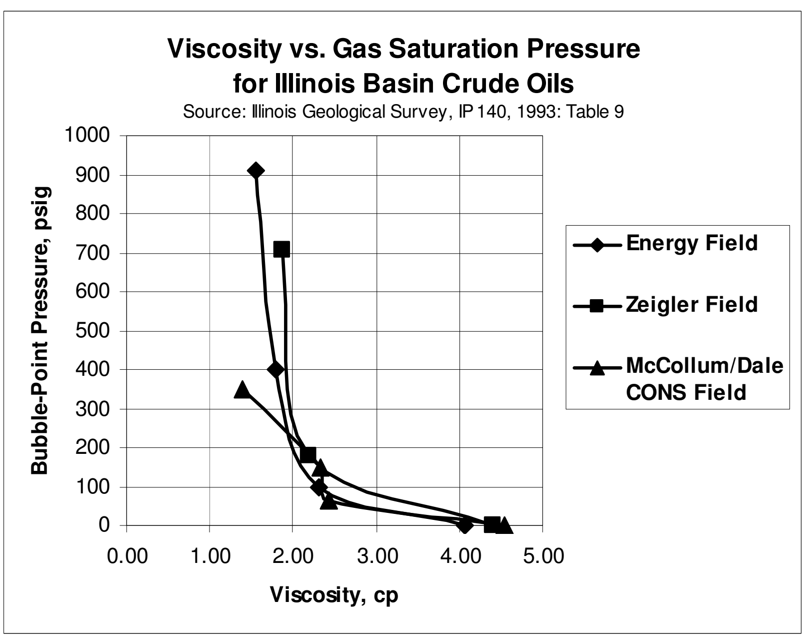
5.0 CARBON DIOXIDE SEQUESTRATION

Figure 5-3 Oil Swelling vs. Viscosity for Illinois Basin Crude Oils



Even though the research team did not publish any direct results for CO_2 swelling versus viscosity, it can be reasonably assumed that oils swelled with CO_2 will exhibit a trend similar to the natural gas results shown in Figure 5-3. The relationship between saturation pressure and viscosity based on the research results is plotted in Figure 5-4 in terms of bubble-point pressure versus viscosity.

Figure 5-4 Viscosity vs. Gas Saturation Pressure for Illinois Basin Crude Oils



5.0 CARBON DIOXIDE SEQUESTRATION

These tests were all conducted with native natural gas as the saturating agent; however there is good evidence from the swelling results that CO_2 would have a similar effect on viscosity. Note the general agreement among the oil samples in this relationship, showing a definite correlation between increased saturation pressure and reduced viscosity. At the modeled maximum reservoir pressure of 840 psia, it can be seen that oil viscosity should be less than one-half the viscosity at stock tank (gas depleted) conditions. It should be noted, however that a stock-tank oil viscosity of 4 to 5 cp is rather fluid, and if the current reservoir pressure is above 50 to100 psig, the improvement in viscosity from gas injection is not large

In summary, re-saturating the crude oil in the typical western Kentucky reservoir with natural gas or CO_2 will have a positive impact on oil swelling and viscosity reduction. Because the Illinois Basin oils tend to be light, low-viscosity crudes, the relative improvement in viscosity will probably be a less important factor in production enhancement than the mechanical drive force provided by the increased gas pressure. From limited published direct laboratory testing, CO_2 should provide superior oil swelling and viscosity reduction compared to natural gas.

Enhanced Oil Recovery

The Kentucky Geological Survey has estimated that immiscible CO_2 enhanced oil recovery will average approximately 6.5% of original oil in place, which is applicable for the pressure and temperature conditions for the typical western Kentucky reservoir.[12] This estimate can be checked against the characteristics derived for the typical western Kentucky reservoir in Table 5-5.

The amount of Remaining Recoverable Oil in Place per acre-foot is equal to the Original Oil in Place per acre-foot, *minus* the Oil Recovery to Date per acre-foot, *minus* the Unrecoverable Oil in Place per acre-foot. Based on the averaged data in Table 5-5:

Original Oil in Place per acre-foot (Table 5-5) = 700 stock-tank barrels

Oil Recovery to Date per acre-foot (Table 5-5) = 250 stock-tank barrels

Unrecoverable Oil in Place per acre-foot = 7758 x Φ x (S_{or}) = 396 stock-tank barrels
where: 7758 = the volume of an acre-foot in barrels

Φ = Porosity = 17% (Table 5-5)

S_{or} = Residual Oil Saturation = 30% (Table 5-5)

Remaining Recoverable Oil per acre-foot = 700-250-396 = 54 stock-tank barrels

Remaining Recoverable Oil (% Original Oil in Place) = 54 / 700 = 7.7%

5.0 CARBON DIOXIDE SEQUESTRATION

The calculations indicate that if 100% of the remaining recoverable oil were somehow recovered through CO_2 injection, which is unlikely due to sweep inefficiencies, it would amount to 7.7% of the original oil in place. This supports the estimate of 6.5% recovery made by the Kentucky Geological Survey.

Enhanced Oil Production Characteristics

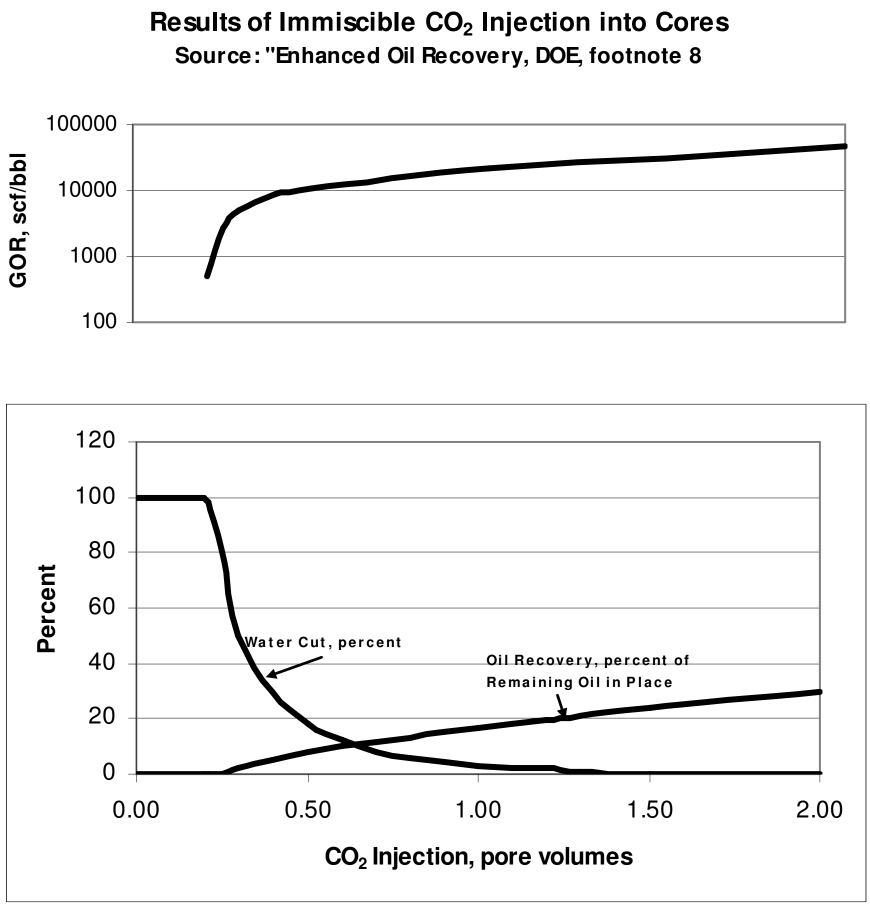
In order to determine the likely average operating characteristics of the typical western Kentucky reservoir, it is necessary to determine the initial daily oil production rate, how the initial rate will decline over time, and the production gas-oil-ratio trend over the life of the project.

Research conducted by the Department of Energy into immiscible CO_2 injection into sandstone cores provides some indications of what to expect.[13] The laboratory tests were conducted on an oil saturated horizontal core that had been first subjected to a simulated water flood, reducing the oil saturation from an initial 64% to 36% after water flooding. The oil that remained in the core was at stock tank conditions. CO_2 was injected under reservoir pressure and temperature at immiscible conditions with the results shown in Figure 5-5. Note that there is no initial oil front, or surge in oil production, rather as the water is evacuated, the oil production commences and undergoes a slow decline in rate with time. The researchers indicated that no significant increase in oil production occurred after 2.0 pore volumes of CO_2 injection. Recovery at 1.0 and 2.0 injected pore volumes was approximately 17% and 28%, respectively, of remaining oil in place. For the typical western Kentucky reservoir, this would amount to 10% and 18%, respectively, of the Original Oil in Place. The water in the core was essentially evacuated by 1.0 pore volume of injection.

Note the gas-oil-ratio (GOR) increases during injection. Examination of the core by CAT-scan after the test revealed that CO_2 had by-passed the oil due to gravity effects. This is borne out by the very high GOR experienced during the injection.

5.0 CARBON DIOXIDE SEQUESTRATION

Figure 5- 5 Results of Immiscible CO_2 Injection into Cores

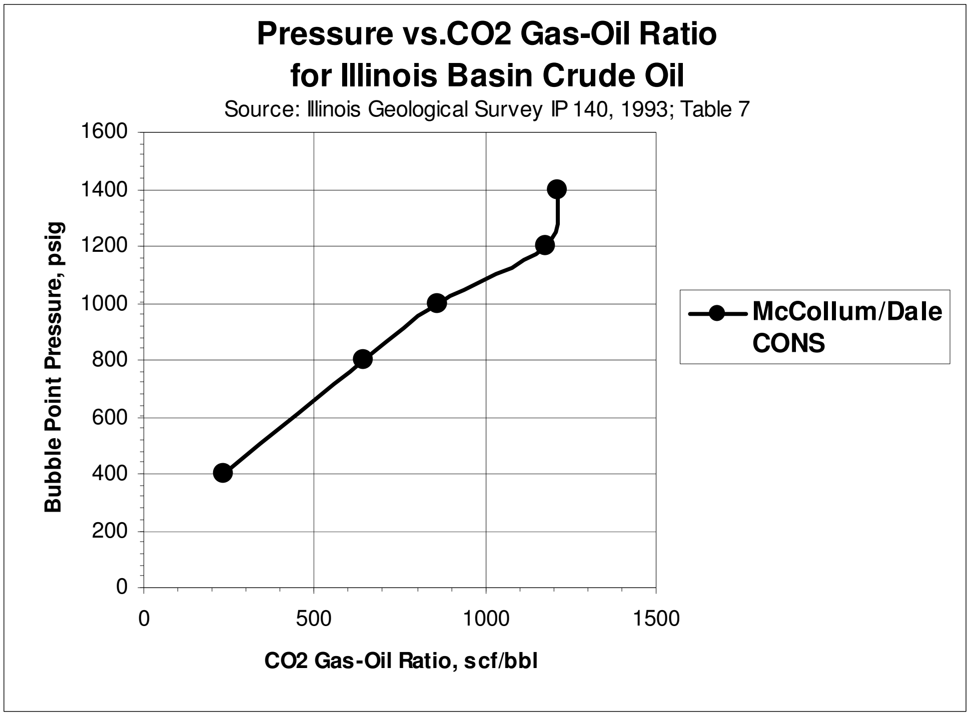


The GOR measured during the test is therefore a product of the CO_2 saturation in the oil being evolved during oil production as well as excess CO_2 that is by-passing the oil. This should reasonably be expected to occur also in actual field production to some extent.

To determine what the CO_2 saturation will be for typical Illinois Basin oils, experiments were conducted by the Illinois Geological Survey on Mississippian crude oil from the Dale Consolidated Field. Figure 5-6 indicates that at the 840 psia reservoir pressure of the typical western Kentucky reservoir, the saturation GOR will be approximately 700 scf/bbl. This was the minimum GOR experienced during the core flood tests depicted in Figure 5-5, confirming again that most of the produced gas was due to by-pass.

5.0 CARBON DIOXIDE SEQUESTRATION

Figure 5-6 Pressure vs. CO_2 Gas-Oil Ratio for Illinois Basin Crude Oil



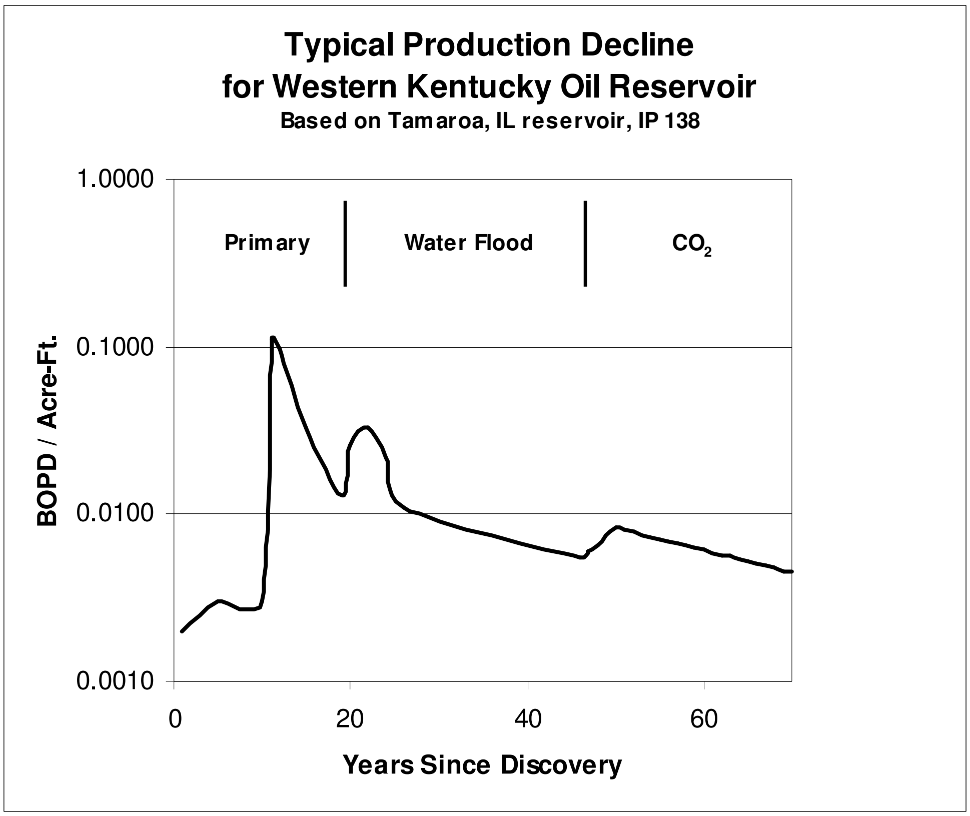
The initial oil production rate and decline rate for a reservoir under immiscible CO_2 injection should bear some relationship to the production trend displayed by the same reservoir under prior water flood, assuming no change in well placement, since both are essentially pressure-maintenance operations. Historic production data is generally not reservoir-specific, such that historic field-wide trends must be used to mimic reservoir production performance.

Table 5-5 cites a historical average production rate of 0.015 bopd/acre-foot for the typical western Kentucky oil reservoir. This is based on actual performance for the Illinois and Kentucky fields listed in Tables 5-2 and 5-4, and represents data that ranges from a low of 0.006 bopd/acre-foot (Stewardson, IL Field) to 0.046 bopd/acre-foot (Zeigler, IL Field). It also represents the historic performance of the fields under their entire life cycle, which includes both primary and water flood operation. A reservoir that historically fit the average production rate performance and also was of the appropriate size is the Tamaroa, IL oil field east reservoir.[14] This reservoir had been discovered in 1942 and began water flood operation in 1952. Its historic production decline curve was used to develop a typical decline curve for the typical western Kentucky reservoir, extended by a simulated CO_2 enhanced recovery decline curve that was consistent with findings of the core flood studies discussed above. Figure 5-7 depicts the resultant oil production trend. Commencement of CO_2 injection results in a building oil

5.0 CARBON DIOXIDE SEQUESTRATION

production rate and then a decline that mimics the decline rate seen for water flood. Associated with this oil production will be a declining water cut as flood water is purged from the reservoir initially and an ever-increasing gas-oil-ratio with time. The produced gas (CO_2) will be continuously re-injected into the reservoir to maintain reservoir pressure. Even though reservoir pressure is being maintained, oil production is expected to decline due to increasing gas saturation around the well bores and resultant reduction in relative permeability to oil.

Figure 5-7 Typical Product Decline for Western Kentucky Oil Reservoir



<u>Injection and Production Schedules</u>

The typical western Kentucky reservoir is assumed to have undergone water flood operations for an extended period. At the time of conversion to CO_2 injection, the water to total fluid production ratio, or "water cut" in excess of 95% is assumed, and water injection rate is approximately twice the initial reservoir oil production rate.[15] The oil and water is assumed to be produced from each well with the aid of a down hole pump. Water and oil are separated at the surface in mechanical separators and the produced water is being re-injected into the injection wells.

5.0 CARBON DIOXIDE SEQUESTRATION

The process envisioned in this study for CO_2 injection makes maximum usage of existing facilities and minimizes the scope of new facilities. CO_2 would essentially replace water as the injectant. Surface and down-hole equipment requirements are discussed more fully in another section of this report.

In the conceptual model, an initial volume, or "charge" of CO_2 would be injected into the existing water injection wells to remove the flood water in the reservoir and re-saturate the remaining oil in place with gas. It is assumed that this charge volume is equal, in gas equivalent, to the historic cumulative oil production of the reservoir plus a re-saturation volume based on CO_2 laboratory tests reduced by an efficiency factor that recognizes that some native gas saturation remains in the reservoir. Because the re-saturation will swell the remaining oil in place, reducing the volumetric capacity, actual reservoir pressure will exceed the discovery pressure initially. With time and additional oil depletion, it is assumed that the reservoir pressure will reach discovery conditions.

From Table 5-5, the oil recovery to date is 250 barrels oil per acre-foot or 250,000 stock tank barrels of oil for the model reservoir. This volume is equivalent to 239,800 Mcf of CO_2, as follows:

From the Ideal Gas Law,

CO_2 Volume at std. Conditions, scf= Oil Volume at reservoir conditions, cu. ft. X P_r /P_s X T_s /T_r

Where: *P_r=Reservoir Pressure, psia*

P_s=Standard Pressure, psia

T_r=Reservoir Temperature, degrees Rankine

T_s= Standard Temperature, degrees Rankine

250,000 S.T.bbls X 1.05 res.bbls./S.T.bbl X5.61 cu ft./bbl X 854.7 psia/14.7 psia X 520°R/544°R

= 81,845,156 std cubic feet (81,800 Mcf), plus

Re-saturation volume= 450,000 S.T.bbls remaining oil in place X 700 scf/S.T.bbl gas-oil ratio from Figure 6 X 0.5 efficiency = 158,000,000 std cubic feet (158,000 Mcf)

The rate of injection for this charge volume mimics the historic water injection rate, or approximately 220 bbls water per day, which is equivalent to approximately 72 Mcfd. The period of time required to inject the charge volume would be 239,800 Mcf / 72 Mcfd = 3,331 days, or 9.1 years. The CO_2 would be injected into each of the 3 injection wells at pressures not exceeding reservoir fracture pressure while the evacuated water and oil is produced under pump assistance at the 8 production wells. Maximum production rate is held to the historic maximum of 110 barrels per day.

After injecting the initial charge, which essentially returns the reservoir to original reservoir pressure with CO_2 replacing water as the drive mechanism, oil production continues with concurrent oil and CO_2 production at the wells. The well stream will require mechanical separation to remove the CO_2 from the oil for re-injection into the injection wells. This will require installation of gas compression.

As indicated in the core studies (Figure 5-5), oil production is expected to increase as CO_2 injection proceeds and water cut diminishes. The maximum oil production rate is modeled at the average rate experienced under water flood (Figure 5-7), or 8.3 bopd. This will occur early in the project, and oil rates will decline each year thereafter similar to the decline experienced under water flood. The total oil recovery is modeled at 45,500 stock tank barrels, or 6.5% of original oil in place. The required production period to attain this recovery is 20 years.

Table 5-6 is the estimated injection and production schedule for the typical western Kentucky reservoir, showing the daily and annual CO_2 injection volumes, daily and annual oil production volumes, cumulative oil production and cumulative pore volume of injected CO_2. (In this instance, pore volume is considered to be total reservoir rock pore volume which is consistent with the definition of pore volume used in the laboratory core results in Figure 5-5.) Gas-oil-ratios were estimated at pore volume increments based on laboratory results in Figure 5-5.

Table 5-6 Production Schedule for Typical Western Kentucky Reservoir

Production Schedule for Typical Western Kentucky Reservoir										
Project Year	Daily CO_2 Charge mcfd	Annual CO_2 Charge mscf	Daily Oil / Water Production bpd	Gas-Oil Ratio mcf/bbl	Daily CO_2 Reinjection mcfd	Annual CO_2 Throughput mscf	Cumulative CO_2 Throughput mscf	CO_2 Pore Volume Throughput	Annual Oil Production bbls	Cumulative Oil Production bbls
1	72	26,300	6.5 / 103.5	0.0	0.0	26,300	26,300	0.07	2,373	2,373
2	72	26,300	7.5 / 102.5	0.0	0.0	26,300	52,600	0.13	2,738	5,111
3	72	26,300	8.3 / 101.7	0.7	5.8	28,420	81,020	0.20	3,030	8,141
4	72	26,300	8.0 / 102.0	0.8	6.4	28,640	109,660	0.27	2,920	8,331
5	72	26,300	7.8 / 102.2	1.0	7.8	29,150	138,810	0.34	2,847	11,178
6	72	26,300	7.5 / 102.5	1.5	11.3	30,420	169,230	0.42	2,738	13,916
7	72	26,300	7.3 / 70.5	2.0	14.6	31,630	200,860	0.50	2,665	16,581
8	72	26,300	7.1 / 0	2.6	18.5	33,050	233,910	0.58	2,592	19,173
9	72	26,300	6.9 / 0	3.8	26.2	35,860	269,770	0.67	2,519	21,692
10	72	3,100	6.7 / 0	5.0	33.5	15,330	285,100	0.70	2,446	24,138
11			6.5 / 0	7.0	45.5	16,600	301,700	0.75	2,373	26,511
12			6.3 / 0	8.5	53.6	19,500	321,200	0.79	2,300	28,811
13			6.1 / 0	10.0	61.0	22,300	343,500	0.85	2,266	31,038
14			5.9 / 0	11.5	67.9	24,800	368,300	0.91	2,154	33,192
15			5.7 / 0	13.0	74.1	27,000	395,300	0.98	2,081	35,273
16			5.6 / 0	14.5	81.2	29,600	424,900	1.05	2,044	37,317
17			5.4 / 0	16.0	86.4	31,500	456,400	1.13	1,971	39,288
18			5.2 / 0	17.6	91.5	33,400	489,800	1.21	1,898	41,186
19			5.1 / 0	19.0	96.9	35,400	525,200	1.30	1,862	43,048
20			4.9 / 0	21.0	102.9	37,600	562,800	1.39	1,789	44,837
21			4.8 / 0	22.0	105.6	38,500	601,300	1.49	1,752	46,589

5.0 CARBON DIOXIDE SEQUESTRATION

The resultant recovery indicated in Table 5-6 shows that the 6.5% recovery (45,500 bbls) is attained at approximately 1.5 pore volumes of CO_2 throughput in the reservoir. This is less than the recovery seen in the laboratory core studies. Based on the historical field trends used to develop the model for the typical western Kentucky reservoir, there is little justification for increasing the enhanced oil recovery projection in an attempt to duplicate laboratory results. There may be some expectation of higher recoveries than predicted in this conservative approach if reservoir conditions are better than average, however large variances are not anticipated.

Post-Production

At the end of enhanced oil production, the reservoir would typically be plugged and abandoned. The volume of extraneous CO_2 that had already been injected (239,800 Mcf) could simply and safely be abandoned in place at a reservoir pressure that matches the native discovery pressure. This would be a fairly routine method for sequestering relatively small, discreet volumes of CO_2. In this case, existing Kentucky State rules and procedures for oil field abandonment should apply.

Summary

Utilizing appropriate analogy from detailed studies of Mississippian-age reservoirs in other parts of the Illinois Basin as well as field-wide data for Kentucky oil production, a typical reservoir was developed and modeled to simulate an enhanced oil recovery operation in western Kentucky. Incorporating laboratory studies of Illinois Basin crude oil characteristics and Department of Energy research into CO_2 core flooding, a 20-year injection and production schedule was estimated for use in determining overall project economics. The results indicate that an enhanced oil recovery factor of 6.5% is reasonable and attainable with possible up-side for slight improvement. The modeled reservoir recovers an additional 45,500 barrels of oil, and provides a potential CO_2 sequestration capacity of approximately 240,000 Mcf.

5.2 MULTIPLE RESERVOIR CO_2 EOR FIELD DESIGN AND OPERATION

The design for a conceptual western Kentucky CO_2 EOR field operation was based on the average reservoir described in Section 5-1 and the production data tabulated in Table 5-6. A workable design was prepared but it was determined that the production numbers would be so small for a single reservoir that a special skid mounted design would be required for each individual reservoir which would ultimately result in the operation having no beneficial economies of scale. It was determined that this design would also have to be repeated for each small reservoir making the operation cumbersome and the investment less attractive. Upon further study, it was determined that the desired economies of scale could be obtained by combining the operations of 15 or more small reservoirs, located in a small geographic area, into one central facility. In this manner a single central process facility can be constructed and operated to separate the oil, produced water and CO_2 and provide for the compression of that CO_2 so it can be recycled to the injection wells in each reservoir

Figure 5-8 illustrates a conceptual design for a 15 reservoir operation tied to a central processing facility. The reservoir placement, although only conceptual for this exercise, does approximate the general northwest trend and scattered distribution found in average Mississippian reservoirs in the Illinois Basin. As described in Section 5-1 each average reservoir is expected to have 3 water injection wells and 8 producing wells and to be near the economic end of secondary water flood depletion. That means that each reservoir is producing less than 5 barrels per day of oil and 100 barrels per day of water.

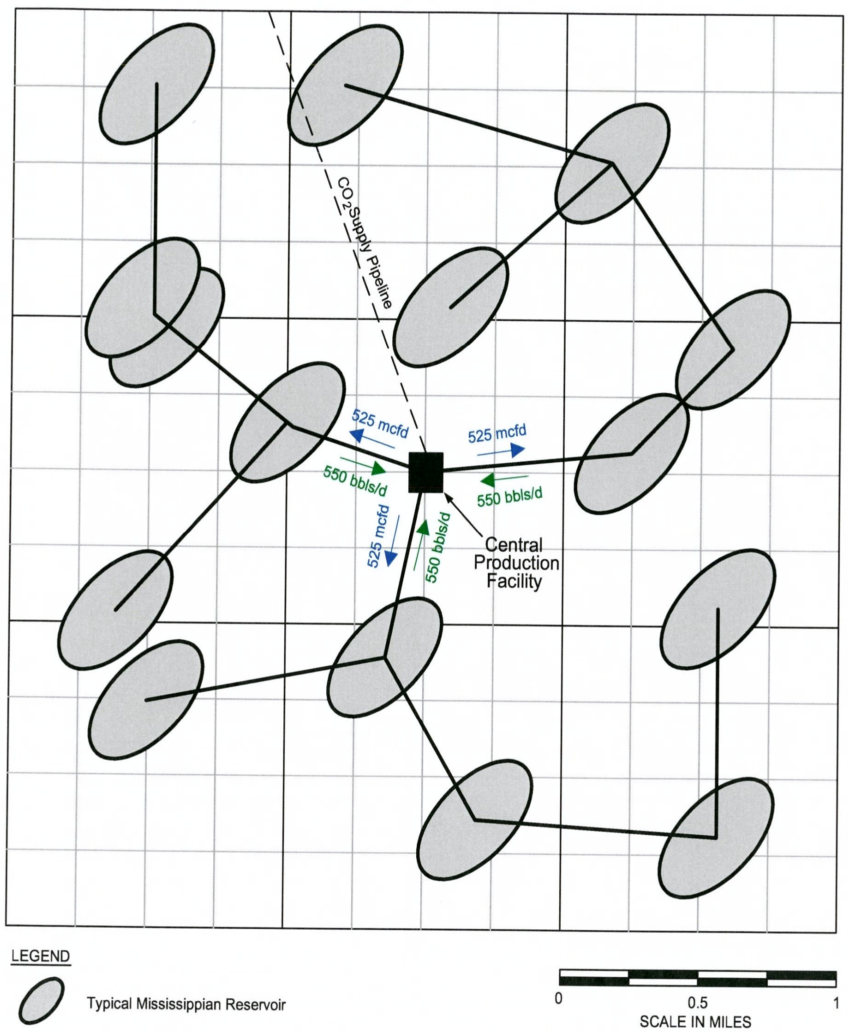
It is assumed that work-overs would be performed on the 3 water injection wells in each of the 15 reservoirs to convert them to CO_2 injection wells at a first year cost of $1,637,730. This is based on DOE's formula for conversion of existing Kentucky wells from their 2006 report: *Basin Oriented strategies for CO_2 EOR*. Cost = c_1D, where c_1 = $19.41 per foot and D is well depth in feet.

The other major first year cost will be $2,958,050 for the installation of the production gathering lines and the CO_2 distribution and injection lines. In this case URS had Energy Management and Services ("EMS") of Versailles, Kentucky perform a conceptual design and opinion of probable cost estimate. It was determined that 49,000 feet of 2.375" O.D. coated steel pipe would be required for the CO_2 and 49,000 feet of 4.5" O.D. plastic pipe would be required for the oil/produced water.

The CO_2 from the plant will be piped into the central process facility and from there it will be distributed to the injection wells. It is expected to take about 10 years to attain 1.5 pore volume throughput in the reservoir at a charge rate of 1.08 MMcfd of CO_2. The CO_2 should start showing up in the production stream at the central process facility in the third year where it will be separated and recycled for injection. In the tenth year, supply of CO_2 from the gasification plant should no longer be required and recycle gas from the central facility will gradually increase to maintain optimal reservoir pressure. It is expected that the recycle gas will continually increase along with the gas-oil ratio. The oil production should peak in the third year and then gradually fall but the EOR operation would continue for at least 20 years and result in 6.5% enhanced recovery or 45,000 barrels per reservoir or 675,000 barrels for a 15 reservoir project.

5.0 CARBON DIOXIDE SEQUESTRATION

Figure 5-8. Conceptual EOR Project Design for Kentucky



ASSUMPTIONS

Each Reservoir is ~100 acres, or ~1/4 mile x 5/8 mile in dimension

Reservoir spacing averages, 360 acres, or ~3/4 miles between reservoir centers

Actual reservoir placement approximates the general Northeast trend and scattered distribution found in the Illinois Basin

Each map line represents 2 flowlines: 1) CO_2 injection lines and 2) Oil production line

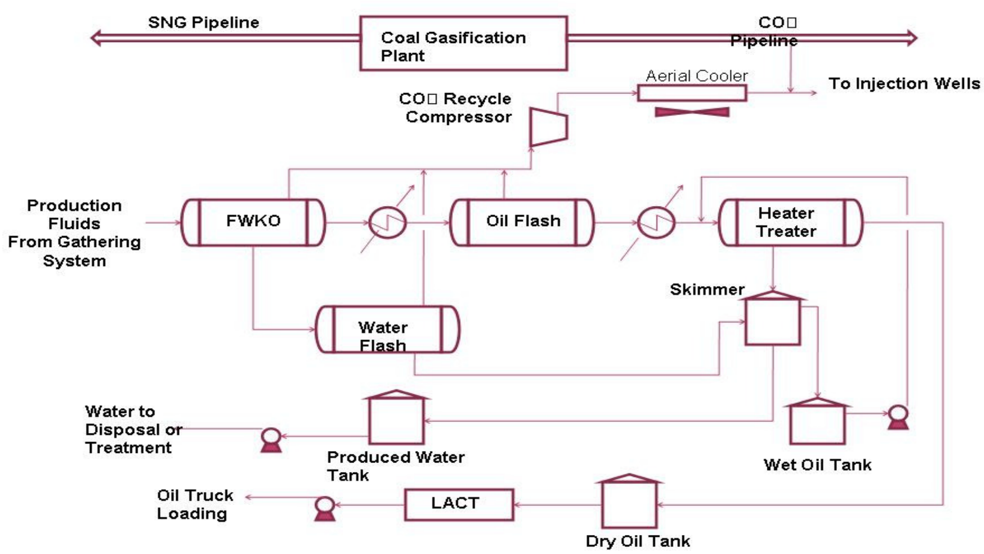
CO_2 Injection Line: Maximum CO_2 injection rate = 105 mcfd per reservoir @ 800 psig, or 525 mcfd for a ground of 5 reservoirs

Oil Production Line: Maximum 110 bbls/day water and oil per reservoir @ 50 psig, or 550 bbls/day for a group of 5 reservoirs

5.0 CARBON DIOXIDE SEQUESTRATION

A simplified process flow sketch for the Central Production Facility is shown in Figure 5-9. The production fluids will flow from the wells to the central facility through the 4.5-inch plastic pipe where it will enter the free water knockout vessel (FWKO). The FWKO is a horizontal 3 phase separator commonly used when the volume of water produced is large in relation to the oil. This will allow the downstream vessels to be smaller. The first compartment of the FWKO is sized so that most of the water will have time to settle to the bottom by gravity and then flow through a control valve to a simple water flash vessel. The oil rises to the top of the water layer and flows over a weir into a second compartment. This compartment has a mist eliminator at the top where CO_2 vapor exits through a control valve to the suction bottle of the 400 hp recycle compressor. The oil flows through a control valve to a heat exchanger and then to the oil flash vessel. The oil and water flash vessels take a drop in pressure to permit the remaining CO_2 in each stream to be released to the recycle compressor suction bottle. The oil flows through another heat exchanger to the heater treater where emulsions are broken down and water droplets collect in the bottom before flowing to a skimmer vessel. The heater treater oil flows to the dry oil tank and then to sales via a lease automated custody transfer unit. The skimmer is sized to allow oil droplets in the water flash and heater treater bottoms to rise and overflow to a wet oil tank from which it is recycled to the heater treater. The skimmer bottoms are pumped from a produced water tank to two water disposal wells which were included in the estimate. The vessels must all be internally epoxy coated because CO_2 in contact with water is extremely corrosive. The cost of this central processing facility is estimated to be $3,267,500.

Figure 5-9. Simplified Process Flow For EOR Central Production Facility



5.0 CARBON DIOXIDE SEQUESTRATION

Table 5-7 presents an estimate of the performance of a conceptual project extending the life of a group of western Kentucky reservoirs 20 years with CO_2-EOR. The analysis performed indicates that such a project provides economic incentives for investment. The total investment of nearly $8 million would be recovered in the first three years. This economic performance is based on $100 per barrel oil and using current dollars. Of course no one can predict how long oil will remain over $100 but many of the costs are related to the oil price and would dampen the effect of falling prices.

TABLE 5-7. ESTIMATED 15 RESERVOIR CO2 - EOR PROJECT PERFORMANCE IN WESTERN KENTUCKY

YEAR	WORKOVER	PLANT INV	CO2 COST	DIST & PROD	CO2 RECYCLE	LIFT	RES O & M	G & A	ROYALTIES	TAXES	TOTAL	INCOME	NET
1	1,637,730		98,550	2,958,050		150,563	607,455	151,604	444,938	195,773	6,244,663	3,559,500	-2,685,163
2	545910	2,267,500	98,550			150,563	607,455	151,604	513,375	225,885	4,560,842	4,107,000	-453,842
3	545910	1,000,000	98,550		31,755	150,563	607,455	151,604	568,125	249,975	3,403,937	4,545,000	1,141,063
4	545910		98,550		35,040	150,563	607,455	151,604	547,500	240,900	2,377,522	4,380,000	2,002,478
5	545910		98,550		42,705	150,563	607,455	151,604	533,813	234,878	2,365,478	4,270,500	1,905,022
6	545910		98,550		61,875	150,563	607,455	151,604	513,375	225,885	2,355,217	4,107,000	1,751,783
7	545910		98,550		79,935	106,489	607,455	142,789	499,688	219,863	2,300,679	3,997,500	1,696,821
8	545910		98,550		101,295	9,718	607,455	123,435	486,000	213,840	2,186,203	3,888,000	1,701,797
9	545910		98,550		143,445	9,444	607,455	123,380	471,750	207,570	2,207,504	3,774,000	1,566,496
10	545910		98,550		183,420	9,171	607,455	123,352	458,625	201,795	2,228,278	3,669,000	1,440,722
11	545910				249,120	8,897	607,455	123,270	444,938	195,773	2,175,363	3,559,500	1,384,137
12	545910				293,460	8,623	607,455	123,216	431,250	189,750	2,199,664	3,450,000	1,250,336
13	545910				333,975	8,349	607,455	123,161	424,875	186,945	2,230,670	3,399,000	1,168,330
14	545910				371,760	8,076	607,455	123,106	403,875	177,705	2,237,887	3,231,000	993,113
15	545910				405,705	7,802	607,455	123,051	390,188	171,683	2,251,794	3,121,500	869,706
16	545910				444,570	7,665	607,455	123,024	383,250	168,630	2,280,504	3,066,000	785,496
17	545910				473,040	7,391	607,455	122,969	369,500	162,608	2,288,873	2,956,500	667,627
18	545910				500,970	7,118	607,455	122,915	355,875	156,585	2,296,828	2,847,000	550,172
19	545910				530,535	6,981	607,455	122,887	349,125	153,615	2,316,508	2,793,000	476,492
20	545910				563,985	6,707	607,455	122,832	335,438	147,593	2,329,920	2,683,500	353,850
21	545910				578,160	6,570	607,455	122,805	328,500	144,540	2,333,940	2,628,000	294,060
													18,860,496

The following is a brief description of each column in table; 5-7

- **Workover -** In the initial year the three water injection wells in each of the 15 reservoirs would have to be evaluated to determine if they can be placed in CO_2 injection service as is or if a tubing or packer change is required. The DOE formula was applied as shown above to calculate the potential investment of $1,637,730.

- **Plant investment** - These investment dollars are required to construct the central processing facility. Since the CO_2 is not expected to show up in the production stream until the third year, $2,267,500 would be expended in the second year and $1,000,000 early in the third year. This cost is nearly 3 times greater than the DOE model but was based on a current estimate.

- **CO_2 Cost** - In years one through ten, a nominal commodity rate of $0.25 per Mcf of CO_2 is applied to the CO_2 delivered from the plant to cover the cost of installing and operating

5.0 CARBON DIOXIDE SEQUESTRATION

a short supply line to these local projects. After year ten, CO_2 recycle volumes should be high enough to maintain reservoir pressure. This cost is not stated separately in the DOE cost model.

- **Distribution and Production Lines** - Because the expected injection into and production out of these reservoirs is expected to be below the DOE ranges, a cost estimate was prepared including all the usual services and accoutrements for 49,000 feet each of 4.5-inch plastic production pipe and 2.375-inch CO_2 steel injection pipe. This resulted in a first year investment cost of $2,958,050.
- **CO_2 Recycle** - The CO_2 Recycle O & M cost was estimated by the DOE cost model and indexed to 1% of the oil price. As the CO_2 recycle increases from 87 Mcfd in year three to 1540 Mcfd in year twenty, this annual cost increases substantially.
- **Lift Cost** -The DOE model calls for a $0.25 per Mcf lift cost applied to total fluids lifted from the wells. This study anticipates that all the bulk of the water will be displaced from the reservoirs in less than eight years. This cost diminishes rapidly after year seven. At some point the gas-oil ratio will increase to the point that the oil will flow without the rod pumps.
- **Reservoir O & M** - The DOE formula appears to provide an unreasonably high cost for operating these shallow wells. A cost of $40,050 was allocated for each of the 15 reservoirs in the O & M column and money for one workover per reservoir per year was allocated in the workover column.
- **G & A** -The general and administrative costs were allocated at 20% of lift and lease O & M per DOE's model.
- **Royalties** - A standard 12.5% royalty was applied.
- **Taxes** - Severance taxes of 4.5% and ad valorem taxes of 1% were set on the oil stream.

If every producer in the fifty mile radius of the gasification plant took advantage of this opportunity, only 4% of the gasification plant's CO_2 could be sequestered in this manner. This requires the plant to adopt another large scale sequestration option. Such options may include sequestration in saline aquifers or large scale sequestration in basins with large quantities of stranded oil reserves. There is no reason that small amounts required for local EOR cannot be made available concurrently with these large sequestration options. Those two options will be described next.

5.0 CARBON DIOXIDE SEQUESTRATION

5.3 DEEP SALINE AQUIFER SEQUESTRATION

As mentioned in 5.0 above, the Feasibility Study, Part I, identified saline aquifers in both Kentucky and Illinois with the capacity to accept and retain the total CO_2 output generated during the operational life of the plant. Significant research has been done and is continuing on this sequestration option. A coal gasification project, if started today, would likely take five years before it can be placed in service. This includes design, permitting, financing and construction. A clear decision on how to proceed with sequestration would help to avoid costly delays in permitting and financing. With additional information from the ongoing research, such as the number and spacing of wells required and plume monitoring requirements, a developer could be relatively certain that this option would safely and permanently sequester all the CO_2.

Figure 5-10 Conceptual Pipeline to Aquifer Sequestration

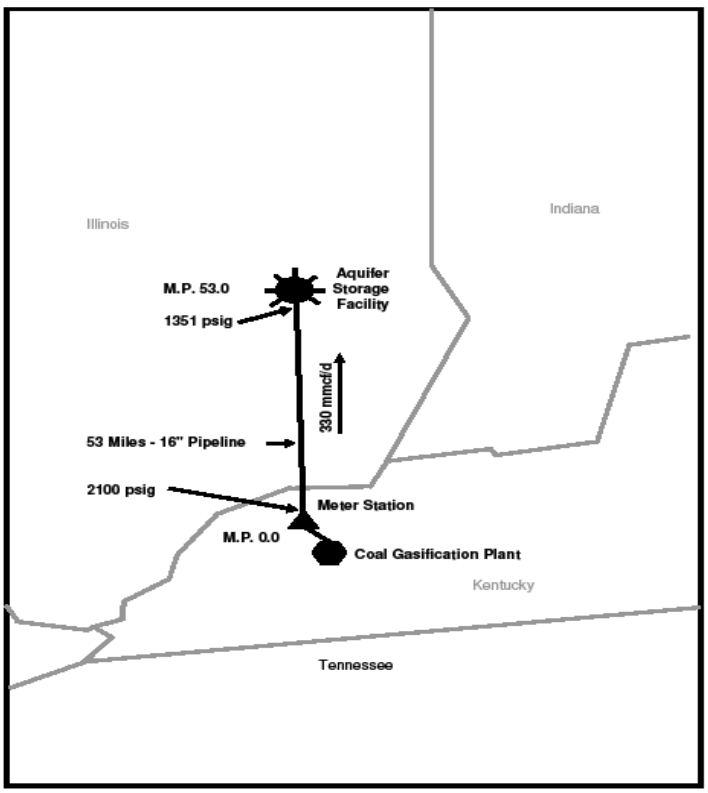
With the best information available today, a developer would likely transport the CO_2 by pipeline to an area above the Mt. Simon formation that is well defined and mapped. For illustration

5.0 CARBON DIOXIDE SEQUESTRATION

purposes, a conceptual pipeline was designed from the plant site to a location near Albion, Illinois, as shown in Figure 5-10.

Hydraulic calculations determined that a 16-inch diameter, 53-mile pipeline could deliver the entire 330 MMcfd of CO_2 to the injection site at a pressure of 1351 psig. This assumes the gasification plant delivers the CO_2 to the pipeline at 2100 psig. Since the gas will still be supercritical it can be pumped with horizontal pumps for injection resulting in an energy savings over compressors. Figure 5-11 illustrates the design operation of this pipeline.

Figure 5-11 Conceptual CO_2 Pipeline to Aquifer Storage



A fairly high level cost estimate termed an "Opinion of Probable Cost" (OPC) was prepared for this 53-mile pipeline. The estimate addressed all the categories of cost for this type of pipeline and associated facilities, (including the Ohio River crossing, road bores and erosion and sedimentation control), short of actually performing the design. The OPC was approximately $80 million including a provision of 15% for omission and contingencies. Also, the OPC for the pipeline is presented in 2008 dollars.

5.0 CARBON DIOXIDE SEQUESTRATION

In addition, at least two injection wells would be required at a cost of $5 million each. This would permit periodic maintenance to be performed on one well without requiring the plant to vent CO_2. Injection tests would be performed during the drilling and completion of the initial well. It may be determined that additional wells will be required after inputting actual injection data into the model. The plume monitoring requirements have not been determined yet and are expected to add significantly to the operating cost.

A project developer could adopt this sequestration option with a reasonably high confidence level that it will perform as designed after fully testing the aquifer. The negative aspect of this option is the high cost to dispose of the CO_2 as a pollutant. The OPC of the pipeline and injection wells as discussed above total around $90 million. In this form of sequestration, this cost will result in adding to the cost of gas to be sold to the prospective markets. Project developers will ultimately use their own economic models to determine the incremental cost of sequestering CO_2 as a pollutant in deep saline aquifers. However, for this report and to give the reader a general idea what this sequestration method adds to the cost of the SNG, a general rule of thumb was applied similar to that used on natural gas pipelines. It was estimated that for a one plant design where a 53-mile, 16-inch pipeline is placed into operation, as discussed above, the unit cost of SNG would increase by approximately $0.25/Mcf. This assumes the coal gasification plant operates 90% of the year producing approximately 175,000 Mcf per day. It also assumes 2008 OPC dollars of approximately $90 million (In today's dynamic world economy, the opportunity of probable cost will likely change significantly from the date of this publication)

In many areas of the country CO_2 is not treated as a pollutant but as a valuable resource which is in short supply. For example in west Texas where CO_2 EOR was pioneered around 1970, they had to experiment with intermittent injection and other methods for stretching the short supply of CO_2. The gasification plant operator could offset some of the costs of capturing and sequestering by pipelining and selling the CO_2 for EOR in areas like Mississippi where the CO_2 is more marketable. This option will be discussed next.

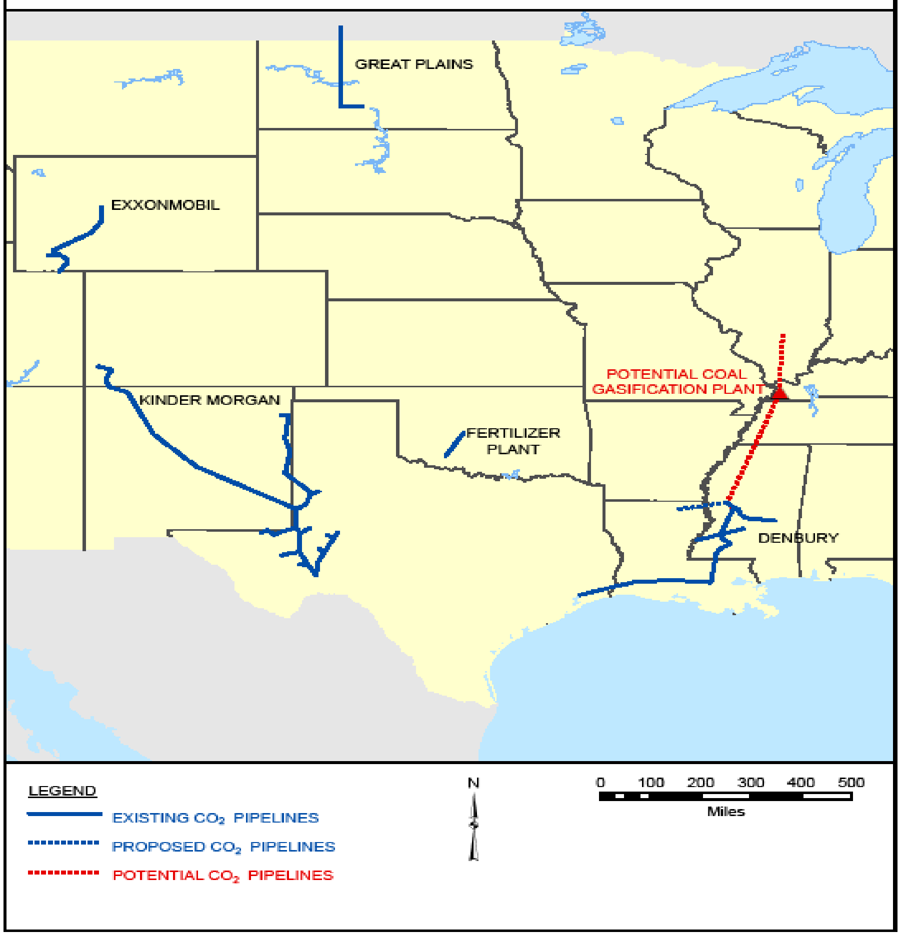
5.4 PIPELINE FOR SEQUESTRATION IN OTHER BASINS

Carbon dioxide can be captured at the coal gasification plant site, but as previously discussed will likely require transportation to a permanent sequestration site. Limited quantities can be transported by truck or rail, but with the production of approximately 330 MMcfd of carbon dioxide from the coal gasification plant described in this report, a pipeline will need to be proposed. Constructing such a pipeline is technically feasibility but if treated as a pollutant as previously discussed, adds to the cost of the gas ultimately delivered to the consuming market. If it is treated as a commodity to large scale EOR operations, it provides value and could contribute to reducing the cost of gas (or at least not add to the cost) ultimately delivered to the consuming market. As previously discussed, the amount of CO_2 which can be used in the

5.0 CARBON DIOXIDE SEQUESTRATION

search area is very limited, therefore a pipeline will likely be required to transport the gas over long distances for use in EOR operations elsewhere. Carbon dioxide pipelines have been in operation in the United States since the early 1970's. Today approximately 3600 miles of CO_2 pipelines operate in the United States.[16] The location of existing CO_2 pipelines are illustrated in Figure 5-12.

FIGURE 5-12 LOCATION OF CO_2 PIPELINES.



The nearest existing CO_2 pipelines and associated large scale EOR operations are located in central Mississippi and operated by Denbury Resources ("Denbury"). Since 1999 Denbury has almost single handedly rescued the decline of oil production in Mississippi. They acquired the naturally occurring CO_2 reserves in the Jackson Dome as well as the stranded oil reserves in multiple fields which had already been depleted through secondary recovery. They built two dehydration plants at Jackson Dome and 270 miles of pipelines to transport CO_2 to the depleted Mississippi fields. Today they are the largest daily injector of CO_2 for EOR in the U.S. at nearly

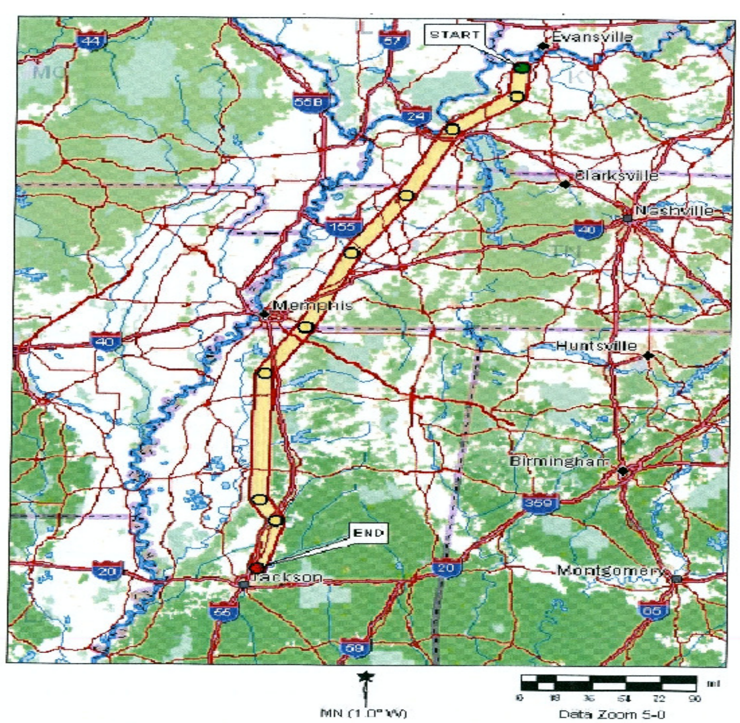
5.0 CARBON DIOXIDE SEQUESTRATION

600 MMcfd and producing nearly 25,000 net barrels of oil per day. An example of Denbury's success is the Mallalieu Area. Denbury improved the performance of those fields from 200 net barrels of oil per day in 2001 to 5,200 barrels per day in 2007. CO_2 injection at Mallalieu peaked at about 280 MMcfd.

Denbury provided the URS study team with a tour of their Tinsley field northwest of Jackson, Mississippi. This is their newest operation which is being built in phases. They are currently injecting 110 MMcfd of CO_2 while construction progresses. By 2013 they expect to be producing 10,000 barrels of oil per day at Tinsley while injecting 200 MMcfd CO_2 from the pipeline and recycling 400 MMcfd of CO_2 from the central processing facility.

Denbury has plans for additional EOR projects in Alabama, Louisiana, and Texas. They have announced plans for an additional 400 miles of CO_2 pipelines including one from the Faustina Gasification Project near St. James, Louisiana to the Houston, Texas area. Therefore, if CO_2 can be delivered to central Mississippi at a competitive price, a CO_2 pipeline from western Kentucky to Mississippi may present the most economically beneficial option for CO_2 sequestration from a Kentucky coal gasification plant. Figure 5-13 illustrates a conceptual route for a Kentucky to Mississippi pipeline.

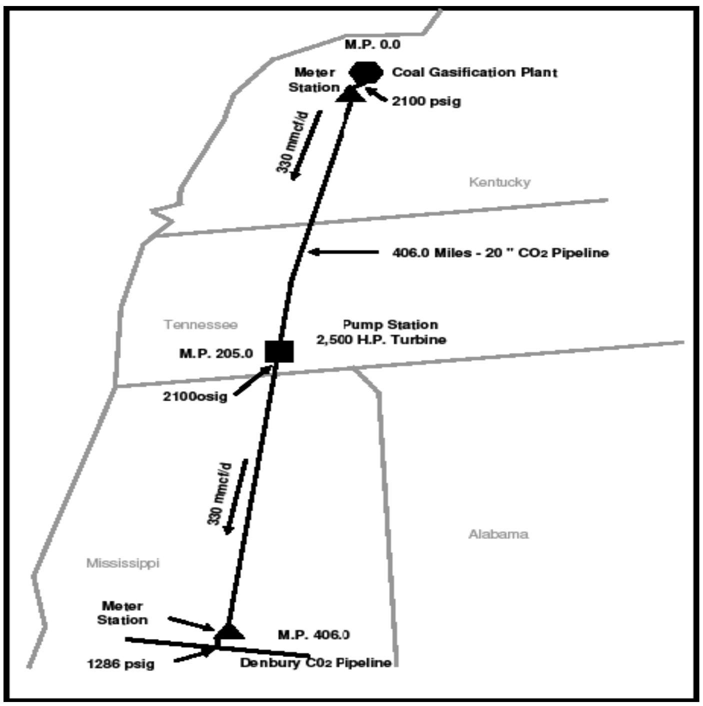
Figure 5-13 Conceptual CO_2 Pipeline Route from Western Kentucky to Mississippi



5.0 CARBON DIOXIDE SEQUESTRATION

As part of the feasibility analysis, URS Corporation requested Energy Management and Services Company to perform a conceptual design and cost estimate for a 406-mile pipeline to transport 330 MMcfd of CO_2 from western Kentucky to just north of Jackson, Mississippi. It was determined that a 20-inch diameter pipeline would be required. The maximum allowable operating pressure was set at 2100 psig. A pump station was also required totaling 2500 horsepower located at the center of the pipeline. This design will allow the CO_2 to be delivered to the Denbury Resources facilities at 1286 psig. For this study it was assumed that this delivery pressure will be compatible with their existing operation at such time an interconnection is made. Figure 5-14 illustrates this flowing design operation of the conceptual pipeline.

Figure 5-14 Conceptual CO_2 Pipeline to Existing EOR Operations Western Kentucky to Mississippi



5.0 CARBON DIOXIDE SEQUESTRATION

The OPC for a pipeline of this design was estimated to be $630 million, including 15% for omission and contingencies. Two custody transfer meter stations and the 2500 horsepower pump station were included in the cost. The estimate is based on 2008 dollars.

A project developer and a CO_2 pipeline developer should have a reasonably high confidence level that this method of sequestration will also perform as designed since CO_2 pipelines are currently in use for several EOR projects throughout the United States. In this method of sequestration, the CO_2 is treated as a commodity and therefore should not add to the cost of the SNG to be sold to prospective markets. In fact, depending on the value placed by the EOR developers/operators, it may contribute revenue to the cost of producing SNG and ultimately reduce the cost of the SNG delivered to the prospective markets.

For discussion here however, it will be assumed that the cost for this method of sequestration does not impact the cost of the SNG sold to the prospective markets. Therefore, the CO_2 is delivered to the CO_2 pipeline developer at no cost. However, the pipeline developer will be required to recover the capital and operating cost of the pipeline through a transportation fee. Again, the pipeline developer will use their own economic models to determine a reasonable transportation fee to receive a fair return on their investment. However, for this report and to give the reader a general idea what minimum value this sequestration method would place on the CO_2 delivered to a Mississippi EOR project, a general rule of thumb was applied similar to that used on natural gas pipelines. It was estimated that for a one plant design where 406 miles of 20-inch pipeline is placed into operation, a transportation fee for the CO_2 would be approximately $1.00/Mcf. This assumes the coal gasification plant operates 90% of the year producing 330,000 Mcf per day of CO_2. It also assumes 2008 OPC dollars of approximately $630 million (In today's dynamic world economy, the OPC will likely change significantly from the date of this publication).

FOOTNOTES

1. Mast, R.F., 1970, "Size, Development and Properties of Illinois Oil Fields": Illinois Geological Survey I.P. 93, 42p.
2. Kentucky Geological Survey website: www.uky.edu/kgs
3. Whitaker, S.T. and Finley, A.K., 1992, "Reservoir Heterogeneity and Potential for Improved Oil Recovery within the Cypress Formation at Bartelso Field, Clinton County, Illinois": Illinois Geological Survey I.P. 137, 40p.
4. Grube, J.P., 1992, "Reservoir Characterization and Improved Oil Recovery from Multiple Bar Sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields, Perry County, Illinois": Illinois Geological Survey I.P. 138, 49p.
5. Rice, R.J., Cole, R.D. and Whitaker, S.T., 1993, "Reservoir Characterization and Potential for Improved Oil Recovery within the Aux Vases Formation at Stewardson Field, Shelby County, Illinois": Illinois Geological Survey I.P. 139, 36p.
6. Sim, S.K., Seyler, B. and Udegbunam, E.O., 1994, "An Integrated Geologic and Engineering Study of the Plumfield Lease Aux Vases Reservoirs, Zeigler Field, Franklin County, Illinois": Illinois Geological Survey I.P. 146, 29p.
7. Seyler, B., 1998, "Geologic and Engineering Controls on Aux Vases Sandstone Reservoirs in Zeigler Field, Illinois": Illinois Geological Survey I.P. 153, 79p.
8. Grube, J.P. and Frankie, W.T., 1999, "Reservoir Characterization and its Application to Improved Oil Recovery from the Cypress Formation (Mississippian) at Richview Field, Washington County, Illinois": Illinois Geological Survey I.P. 155, 39p.
9. Campbell & Rickman Petroleum Consultants, 1962, "Engineering Study of All Reservoirs, [confidential] Lease Group, Poole Field, Henderson and Webster Counties, Kentucky": 154p.
10. Sim, S.S.K., 1993, "Pressure-Volume-Temperature Correlations for Crude Oils from the Illinois Basin": Illinois Geological Survey I.P. 140, 41p.
11. ibid.
12. Harris, D. C. , 2007, Kentucky Consortium for Carbon Sequestration-Organization, Goals and Future": Presentation in Lexington, Kentucky.
13. Chung, T.H., 1986, "Development of Improved Immiscible Gas Displacement Methods": United States Department of Energy Office of Oil, Gas and Shale Technology Progress Review 47, pp.65-66.
14. Grube, J.P., 1992, "Reservoir Characterization and Improved Oil Recovery from Multiple Bar Sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields Perry County, Illinois": Illinois Geological Survey I.P. 138, 49p.
15. ibid
16. .CRS Report for Congress, Carbon Dioxide Pipelines for Carbon Sequestration: Emerging Policy Issues. April 19, 2007.